



**HAND DELIVERED**

06.02400

JUL 17 2006

UTAH DIVISION OF  
SOLID & HAZARDOUS WASTE

**INDUSTRIAL LANDFILL**  
**PERMIT RENEWAL APPLICATION**  
**HUNTINGTON POWER PLANT**  
**FINAL REVISION**

**DATE SUBMITTED:**

**JULY 10, 2006**

**PREPARED FOR PACIFICORP**

**BY**



**HAND DELIVERED**

06.02400

JUL 17 2006

UTAH DIVISION OF  
SOLID & HAZARDOUS WASTE

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Please see the following notes which detail the contents and updates to the Hunter Industrial Solid Waste Landfill *Permit Renewal Application*:

**Tab 1. Permit Application Form and Revised Narrative**

The entire narrative section (General Report, Technical Report, and Financial Assurance) was reformatted into a contiguous Microsoft Word format and resubmitted. Also, narrative headings were updated to include references to the *Utah Solid Waste Permitting and Management Rules*. An original updated Solid Waste Permit Application Form has been included at the beginning of the document.

**Tab 2. Revised Plan Sheets**

All Plan Sheets and site maps are included in this section for reference.

**Tab 3. Appendix A**

A copy of the updated Class IIIb Landfill Permit Application Form included in Tab 1 is provided.

**Tab 4. Appendix B**

Proof of ownership and legal documents for the Hunter Landfill are included.

**Tab 5. Appendix C**

Copies of industrial landfill inspection forms referenced in this document are included in this section.

**Tab 6. Appendix D**

A complete copy of the Huntington Power Plant *Industrial Landfill Operations Plan* is included in this section.

**Tab 7. Appendix E**

A complete copy of the *Huntington Power Plant Emergency Procedures* is included.

**Tab 8. Appendix F**

Updated closure/post-closure costs have been calculated, with cost spreadsheets and support documentation provided.

**Tab 9. Appendix G**

Financial assurance information is included in this section.

**NOTE:** An electronic copy of the complete Hunter Power Plant Industrial Solid Waste Landfill *Permit Renewal Application* document (Adobe format) is included on a CD inside the front cover of this document.

**UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY**

**DIVISION OF SOLID AND HAZARDOUS WASTE**

**APPLICATION FOR A PERMIT TO OPERATE A CLASS III LANDFILL**

The applicant shall submit an original permit application, which includes a general report and a technical report, to:

Dennis R. Downs, Director  
Division of Solid and Hazardous Waste  
Utah Department of Environmental Quality  
PO Box 144880  
Salt Lake City, Utah 84114 - 4880

(Note: When the application is determined to be complete, submittal of the original complete permit application and one copy of the complete application will be required.)

**PART I - GENERAL INFORMATION**

1. Name of Facility Huntington Plant
2. Site Location Highway 31 West of Huntington
3. Facility Owner PacifiCorp Energy
4. Facility Operator PacifiCorp Energy
5. Contact Person Kerry Powell

Address P.O. Box 680  
Huntington, UT 84528

Telephone (435) 687-4331

6. Type of Facility:  
☐ Class IIIa Landfill ☒ Class IIIb Landfill
7. Type of Application  
☒ Initial Application ☐ Permit Renew

8. Property Ownership

☒ Presently owned by applicant

☐ To be purchased by applicant

☐ To be leased by applicant

Property owner (if different from applicant)

Name \_\_\_\_\_

Address \_\_\_\_\_

Telephone \_\_\_\_\_

9. Certification of submitted information.

[Signature]  
(Name of Official)

VP Engineering & Ops Support  
(Title)

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Signature: Patricia Day

Date

7/10/06

SUBSCRIBED AND SWORN to before This

10<sup>th</sup>

day of

July

, 20 06

My commission expires on the

3<sup>rd</sup>

day of

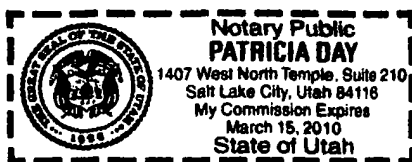
March

, 20 10

Notary Public in and for

(SEAL) \_\_\_\_\_

County, Utah.



**Important Note:** The following checklist is for the permit application and addresses only the requirements of the Division of Solid and Hazardous Waste. Other federal, state, or local agencies may have requirements that the facility must meet. The applicant is responsible to be informed of, and meet, any applicable requirements. Examples of these requirements may include obtaining a conditional use permit, a business license, or a storm water permit. The applicant is reminded that obtaining a permit under the *Solid Waste Permitting and Management Rules* does not exempt the facility from these other requirements.

An application for a permit to construct and operate a landfill is the documentation that the landfill will be located, designed, constructed, and operated to meet the requirements of Rules R315-302, R315-303, R315-308, R315-309, and R315-315 of the *Utah Solid Waste Permitting and Management Rules* and the *Utah Solid and Hazardous Waste Act* (UCA 19-6-101 through 123). The application should be written to be understandable by regulatory agencies, landfill operators, and the general public. The application should also be written so that the landfill operator, after reading it, will be able to operate the landfill according to the requirements with a minimum of additional training.

Copies of the *Solid Waste Permitting and Management Rules*, the *Utah Solid and Hazardous Waste Act*, along with many other useful guidance documents can be obtained by contacting the Division of Solid and Hazardous Waste at 801-538-6170. Most of these documents are available on the Division's web page at [www.eq.stat.ut.us/eqshw/dshw-1.htm](http://www.eq.stat.ut.us/eqshw/dshw-1.htm). Guidance documents can be found at the solid waste section portion of the web page.

When the application is determined to be complete, the original complete application and one copy of the complete application are required along with an electronic copy.

## **CHECKLIST OF ADDITIONAL INFORMATION REQUIRED**

(Please see Section R315-310-5 of the *Utah Solid Waste Permitting and Management Rules*)

### **PART II - GENERAL REPORT**

#### INTRODUCTION

- ☒ Completed PART I - GENERAL INFORMATION (R315-310-3(1)(a))
- ☒ General description of the facility (R315-310-3(1)(b))
- ☒ Legal description; proof of ownership, lease agreement, or other mechanism; latitude and longitude of the site; and land use and zoning of surrounding area (R315-310-3(1)(c))

☒ The types of waste and area served by the facility (R315-310-3(1)(d))

☒ A demonstration that the landfill is not a commercial landfill

PLAN OF OPERATION (R315-310-3(1)(e))

☒ An intended schedule of construction (R315-302-2(2)(a))

☒ A description of on-site waste handling procedures and an example of the form that will be used to record the weights or volumes of waste received (R315-302-2(2)(b) and R315-310-3(1)(f))

☒ A schedule for conducting inspections and monitoring and examples of the forms used to record the results of the inspections and monitoring (R315-302-2(2)(c) , R315-302-2(5)(a), and R315-310-3(1)(g))

☒ Contingency plans in the event of a fire or explosion (R315-302-2(2)(d))

☒ Corrective action programs to be initiated if ground water is contaminated (R315-302-2(2)(e))

☒ Contingency plans for other releases, e.g. explosive gases or failure of run-off collection system (R315-302-2(2)(f))

☒ A plan to control fugitive dust generated from roads, construction, general operations, and covering the waste (R315-302-2(g))

☒ Description of maintenance of installed equipment (R315-302-2(2)(h))

☒ Procedures for excluding the receipt of Regulated hazardous or PCB containing waste (R315-302-2(2)(i))

☒ Procedures for controlling disease vectors (R315-302-2(2)(j))

☒ A plan for alternative waste handling (R315-302-2(2)(k))

☒ A general training and safety plan for site operations (R315-302-2(2)(n))

☒ Any other items not covered above as to how the facility will meet the requirements of Rule R315-304 (R315-310-5(2)(e))

☒ Any other site specific information pertaining to the plan of operation required by the Executive Secretary (R315-302-2(2)(o))

### **PART III TECHNICAL REPORT**

#### MAPS

- ☒ Topographic map drawn to the required scale and contours showing the boundaries of the landfill unit; design and location of the run-on/run-off control structures; and the borrow and fill areas (R315-310-4(2)(a)(i))
- ☒ Most recent U.S. Geological Survey topographic map, 7-1/2 minute series, showing the waste facility boundary; the property boundary; surface drainage channels; existing utilities and structures within one-fourth mile of the site; and the direction of the prevailing winds (R315-310-4(2)(a)(ii))

#### ENGINEERING REPORT - PLANS, SPECIFICATIONS, AND CALCULATIONS

- ☒ Cell design, cover design, fill methods, elevation of final cover including plans and drawings (R315-310-3(1)(b))
- ☒ Design and location of run-on and run-off control systems (R315-310-5(2)(b))

#### CLOSURE PLAN (R315-310-3(1)(h) and R315-310-5(2)(c))

- ☒ Closure schedule (R315-310-4(2)(d)(i))
- ☒ Design of final cover (R315-310-4(2)(c)(iii) and R315-305-5(5))
- ☒ Capacity of site in volume and tonnage (R315-310-4(2)(d)(ii))
- ☒ Final inspection by regulatory agencies (R315-310-4(2)(d)(iii))

#### POST-CLOSURE CARE PLAN (R315-310-3(1)(h))

- ☒ Site monitoring, if required (R315-310-4(2)(e)(i))
- ☒ Changes to record of title, land use, and zoning restrictions (R315-310-4(2)(e)(ii))
- ☒ Maintenance activities to maintain cover and run-on/run-off control systems (R315-310-4(2)(e)(iii))
- ☒ List the name, address, and telephone number of the person or office to contact about the

facility during the post-closure care period (R315-310-4(2)(e)(vi))

FINANCIAL ASSURANCE (R315-310-3(1)(j))

- ☒ Identification of closure costs including cost calculations (R315-310-4(2)(d)(iv))
- ☒ Identification of post-closure care costs including cost calculations (R315-310-4(2)(e)(iv))
- ☒ Identification of the financial assurance mechanism that meets the requirements of Rule R315-309 and the date the mechanism will become effective (R315-309-1(1))

SPECIAL REQUIREMENTS FOR A CLASS IIIa LANDFILL (R315-304-5(7)(b))

- ☐ A geohydrological assessment of the site (R315-310-4(2)(b))
- ☐ An engineering report, plans, specifications, and calculations (R315-310-4(2)(c))
- ☐ A ground water monitoring plan (R315-304-5(4) and R315-310-4(2)(c)(vi))
- ☐ A closure plan that meets the requirements of R315-303-3(4) (R315-304-5(2)(a))

Revision date February 21, 2002

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## 1.0 PART I -- GENERAL INFORMATION (R315-310-3(1)(a))

PacifiCorp has completed this Application for a Permit to Operate a Class IIIb Landfill at the Huntington Power Plant. The original permit application form is included in the opening pages of this document. A copy of the application form is also included in Appendix A.

## 2.0 PART II -- GENERAL REPORT

### 2.1 INTRODUCTION

PacifiCorp respectfully submits this document as support information for the application to operate an industrial solid waste landfill at the Huntington Power Plant near Huntington, Utah. This application has been formatted to follow the sequence of requirements and standards set forth in the Utah Division of Solid and Hazardous Waste (DSHW) Solid Waste Rules (Section R315). Following each outline heading in this document is a reference to the corresponding section of the DSHW regulations.

PacifiCorp complies with the DSHW Rules and Regulations through the use of its *Landfill Operations Plan*. Many of the sections in this document contain references or direct passages from this operations plan. A complete copy of the plan is included in Appendix D.

#### 2.1.1 General Description of the Facility (R315-310-3(1)(b))

The Huntington Plant is a coal-fired electrical generation plant owned and operated by PacifiCorp and located near Huntington, Utah. The Huntington Plant disposes of ash from burning coal, industrial wastes, and scrubber sludge at its landfill site located near the power plant facility. This site is comprised of an original ash landfill that was closed in 2002, and a new ash landfill which is now being used. A specific location within the original ash landfill area is designated for all industrial waste. Industrial waste has been defined as any waste generated other than burned coal waste, scrubber sludge, or wastes associated with the production of electricity. Hazardous or PCB containing wastes are excluded from the landfill. **This permit application only applies to the industrial waste portion of the Huntington landfill**, as ash landfills are exempt from DSHW permitting rules and regulations.

Annual industrial waste volume accounts for approximately 1600 cubic yards per year. An existing gravel road is the primary access road from the power plant to the landfill. Please see attached Plan Sheets 3 through 6 for various figures of the existing landfill.

Operator information for the Huntington Plant is as follows:

**Applicant:** PacifiCorp  
1407 W. North Temple, Room 320

**Property Owner:** Salt Lake City, UT 84116  
PacifiCorp

**Property Address:** Highway 31 W. of Huntington City  
Huntington, UT

**Landfill Manager:** Darce Guymon  
(435) 687-4305

### **2.1.2 Legal Description and Proof of Ownership (R315-310-3(1)(c))**

The following legal description is provided for the Huntington Industrial Solid Waste Landfill:

PacifiCorp Huntington Plant -- WASTE AREA DESCRIPTION:

Beginning at a point which is S 0° 07' 50" W, 697.86 feet and N 89° 52' 10" W, 1149.00 feet from the Northeast corner of the Southeast quarter of Section 1, T. 17 S., R. 7 E., Salt Lake Meridian, Utah; Thence S 60° 28' 19" W, 864.69 feet; Thence S 55° 17' 26" E, 553.10 feet; Thence N 59° 06' 10" E, 563.39 feet; Thence N 22° 20' 53" W, 488.50 feet to the point of beginning.

Containing 8.068 acres m/l.

Basis of Bearing: S 0° 07' 50" W between the East Quarter Corner of Section 1, T. 17 S., R. 7 E. SLM and the South Sixteenth Corner of Section 6, T. 17 S., R. 8 E. SLM, as determined by GPS observations. Both corners being monumented with 1982 BLM Caps.

Please refer to Appendix B for proof of ownership and warranty deed information.

### **2.1.3 Latitude and Longitude Coordinates (R315-310-3(1)(c))**

Latitude and longitude coordinates for the Huntington Industrial Solid Waste Landfill are as follows:

39° 22' 10" N, 111° 04' 52" W

### **2.1.4 Land Use and Zoning Map (R315-301-3(1)(c))**

A zoning map showing land uses of the surrounding area is attached as Plan Sheet 2.

### **2.1.5 Types of Waste and Area Served (R315-310-3(1)(d))**

Typical plant generated industrial wastes deposited in the industrial landfill include paper products, plastic and metal drums, dirt, wood products, lunch room wastes, scrap metal, drained filters, and digested domestic wastewater treatment plant sludge which meet the

requirements of R315-315.5 and the Utah Division of Water Quality. Hazardous or PCB containing wastes are excluded from the landfill.

#### **2.1.6 Non-Commercial Landfill Demonstration**

The Huntington Industrial Waste Landfill is not open to the public. It receives waste generated solely from on site operations. Security at the plant regulates entry and exit of the general public onto the property.

### **2.2 PLAN OF OPERATION (R315-310-3(1)(e))**

#### **2.2.1 Intended Construction Schedule (R315-302-2(2)(a))**

The industrial landfill is located within the boundary of the old ash landfill, and consists of approximately 8.07 acres; however, only 2.85 acres is currently proposed for active waste proposal. At the current waste volume of 1600 cubic yards per year, the industrial landfill will provide disposal capacity until the year 2027. The industrial waste landfill will be closed in the year 2027, or this permit will be modified to include details of any expansion of the active waste disposal area..

Please see attached Plan Sheets 3 through 6 for detailed information on the industrial waste landfill..

#### **2.2.2 On-Site Waste Handling Procedures (R315-302-2(2)(b) and R315-310-3(1)(f))**

Included is an excerpt from the Huntington Plant *Landfill Operations Plan*, Waste Description and Quantities section:

*Industrial wastes should be disposed of within the locations shown on Plan Sheets 1 through 4. These materials should be processed to the smallest practical volume during placement in the landfill. After reducing the volume of the wastes, the materials should be covered with at least 6 inches of compacted fly or bottom ash and then a thin veneer of pyrites or bottom ash by the end of each day that trash is deposited in the landfill. The wastes should be shaped so that water does not pond on top of the wastes. Based on the existing volume identified for the industrial wastes of 1,600 cubic yards per year, the industrial waste landfill will provide disposal capacity until the year 2027.*

Hazardous or PCB containing wastes are excluded from the industrial landfill. All sludges will be dewatered and must pass a paint filter test before being disposed of in the landfill. At least one percent (1%) of waste loads will be reviewed and characterized in detail and recorded on a log sheet. Inspection procedures will consist of the waste being spread out on the ground, and the perimeter of the waste walked to check for hazardous or PCB containing materials. Inspection details will be recorded on a log sheet. The log sheet instructs that hazardous wastes are not permitted in the landfill, and contains a list of prohibited materials. Any prohibited materials will be removed from the waste load,

containerized, and reported to the Landfill Manager. A copy of the Weight and Volume Log Sheet used by landfill personnel is included in Appendix C.

Please refer to Appendix C for a copy of the Weight and Volumes form used by landfill personnel. A complete copy of the Huntington Plant *Landfill Operations Plan* is located in Appendix D.

#### **2.2.3 Landfill Inspections and Monitoring (R315-310-3(1)(g))**

Inspections will be conducted monthly to identify problems in time to correct them before they harm human health or the environment. Please see Appendix C for the Inspection and Monitoring sheet.

#### **2.2.4 Fire/Explosion Contingency Plans (R315-302-2(2)(d))**

The Huntington Plant *Emergency Procedures (HTG-SAF-002)* shall be abided by in the event of a fire, explosion, and other releases such as explosive gases or run-off collection failure. A complete copy of the *Huntington Plant Emergency Procedures* is located in Appendix E.

#### **2.2.5 Ground Water Corrective Action Program (R315-302-2(2)(e))**

An investigation shall be initiated if contamination is detected in the groundwater. The investigation shall involve working in accordance with state agencies to determine the extent of the problem and the proper solution.

#### **2.2.6 Contingency Plans for Other Releases (R315-302-2(2)(f))**

The Huntington Plant *Emergency Procedures (HTG-SAF-002)* shall be abided by in the event of a fire, explosion, and other releases such as explosive gases or run-off collection failure. A complete copy of the *Huntington Plant Emergency Procedures* is located in Appendix E.

#### **2.2.7 Fugitive Dust Control (R315-302-2(g))**

Detailed descriptions of the methods to be implemented for controlling dust are included in the Huntington Plant Title V Air Permit and should be referred to as necessary.

#### **2.2.8 Maintenance of Installed Equipment (R315-302-2(2)(h))**

As a Class IIIb landfill, the Huntington Industrial Solid Waste Landfill does not operate or maintain any leachate systems, gas collection systems, or ground water monitoring systems.

#### **2.2.9 Exclusion of Hazardous/PCB Waste (R315-302-2(2)(i))**

Hazardous or PCB containing wastes are excluded from the landfill. At least one percent (1%) of waste loads will be reviewed and characterized in detail by the truck driver and recorded on a log sheet, as described in Section 2.2.2. The driver is instructed and the log sheet reminds him that hazardous wastes are not permitted in the landfill. A copy of the Log Sheet used by landfill personnel is included in Appendix C.

#### **2.2.10 Control of Disease Vectors (R315-302-2(2)(j))**

After reducing the volume of the waste, the materials should be covered with at least 6 inches of compacted fly or bottom ash and a thin veneer of pyrites or bottom ash by the end of each day that trash is deposited in the landfill.

#### **2.2.11 Alternative Waste Handling (R315-302-2(2)(k))**

In the occurrence that the industrial landfill is inoperative, solid waste shall be sent to the East Carbon Landfill or the Emery County Landfill.

#### **2.2.12 General Safety Training for Site Operations (R315-302-2(2)(n))**

Training may be needed when new personnel are hired or to increase the awareness of the existing employees. This training should be performed as needed to assist the employees in executing and fulfilling their responsibilities. The *Power Supply Operating Rules Handbook* and the *Landfill Operations Plan* will be used for training personnel and providing safety guidelines. Training records will be kept identifying who was trained, the training subject, and the date trained.

Training sessions are documented and kept on file by the Landfill Manager. Please see Appendix C for a copy of the Industrial Waste Landfill Training Sign-In Sheet. A complete copy of the Huntington Plant *Landfill Operations Plan* is located in Appendix D.

#### **2.2.13 Regulatory Requirements of Rule R315-304 (R315-310-5(2)(e))**

Included is an excerpt from the Huntington Plant *Landfill Operations Plan*, Regulatory Requirements section:

##### ***Regulatory Requirements***

*Utah Administrative Code Regulation R315-304 applies to the Huntington Plant landfill operations. These regulations classify industrial landfills into two categories: Class IIIa and Class IIIb. The Huntington Plant industrial landfill meets the requirements for a Class IIIb classification. The landfill is not open to the public, it receives waste generated solely from on site and it does not receive hazardous waste. Industrial waste has been received at the landfill prior to 1998; thus the landfill is an existing Class IIIb landfill. Existing Class IIIb landfills have no siting restrictions. The regulatory*

*requirements for operations, closure and post-closure care for Class IIIb Landfills are summarized below:*

- 1. Develop, keep on file, and abide by a plan of operation approved by the Utah Department of Environmental Quality (UDEQ) Executive Secretary. The plan of operation shall include the following:*
  - A. Intended Schedule of Construction*
  - B. Description of on-site solid waste handling procedures*
  - C. Schedule for conducting inspections and monitoring the facility*
  - D. Contingency plans in the event of a fire or explosion*
  - E. Contingency plans for other releases such as failure of run-off containment system*
  - F. Plan to control fugitive dust*
  - G. Procedures for excluding the receipt of hazardous waste or waste containing PCBs*
  - H. Closure and post-closure care plans*
  - I. Cost estimates and financial assurance*
  - J. General training and safety plan for site operators*
- 2. Maintain and keep on-site or at a location approved by the UDEQ Executive Secretary the following:*
  - A. Weights or volumes, number of vehicles entering and the types of wastes received each day*
  - B. Deviations from the approved plan of operation*
  - C. Training and notification procedures*
  - D. Inspection log*
  - E. Closure and post-closure plans*
  - F. Cost estimates and financial assurance documentation*
- 3. Prepare an annual report and place the report in the facility's operating record. A copy of the report shall be submitted to the Executive Secretary by March 1<sup>st</sup> of each year. The annual report shall cover facility activities during the previous year and must include the following information:*
  - A. Name and address of facility*
  - B. Calendar year covered by the report*
  - C. Annual quantity in tons or cubic yards and estimated in-place density in pounds per cubic yard of solid waste handled*
  - D. Annual update of the required financial assurance mechanism*
  - E. Training programs or procedures completed*
- 4. Inspect the landfill facility to prevent malfunctions and deterioration, operator errors, and discharges which may cause or lead to the release of wastes to the environment or to a threat to human health. The inspections must be conducted with sufficient frequency (no less than quarterly) to identify problems in time to correct them before they harm human health or the environment. The inspection log or summary shall include the following:*

- A. *Date and time of inspection*
  - B. *Printed name and handwritten signature of the inspector*
  - C. *Notation of observations made and the date and nature of any repairs or corrective action*
  - D. *Logs must be kept for a minimum of three years*
- 5. *Design the landfill to minimize the acceptance of liquids and control storm water run on/run-off.*
- 6. *Provide for the following:*
  - A. *Fencing at the property boundary or the use of other artificial or natural barriers to impede entry by the public and large animals. A lockable gate shall be required at the entry to the landfill.*
  - B. *Erecting a sign at the facility entrance that identifies at least the name of the facility, unacceptable materials, and an emergency telephone number.*
  - C. *Adequate fire protection to control any fires that may occur at the facility.*
  - D. *Preventing the potential harborage in active areas of rat and other vectors*
  - E. *Minimize the size of the unloading area and working face as much as possible*
  - F. *Approach and exit roads of all-weather construction, with traffic separation and traffic control on-site and at the site entrance.*
  - G. *Communication, such as telephone or radio, between employees working at the landfill and management offices to handle emergencies*
- 7. *Prevent the disposal of unauthorized waste by ensuring that at least one person is on site during hours of operation and shall prevent unauthorized disposal during off-hours by controlling entry.*
- 8. *Employ measures to prevent emissions of fugitive dusts, when weather conditions or climate indicate that transport of dust off-site is liable to create a nuisance.*
- 9. *Cover timber, wood, and other combustible waste with a minimum of six inches of soil, or equivalent, to avoid a fire hazard.*
- 10. *Plats and a statement of fact concerning the location of any disposal site shall be recorded as part of the record of title with the county recorder not later than 60 days after certification of closure. Proof of the record of title filing shall be submitted to the Executive Secretary.*
- 11. *Close the facility in a manner that will:*

- A. *Minimize the need for maintenance*
  - B. *Minimize or eliminate threats to human health and the environment from escape of solid waste constituents, leachate, gases, or contaminated run-off to the groundwater, surface water, or the atmosphere*
  - C. *Prepare the facility for the post-closure period*
12. *Develop, keep on file and abide by a closure plan approved by the UDEQ Executive Secretary.*
13. *The closure plan shall project time intervals at which sequential partial closure, if applicable, is to be implemented and identify closure cost estimates and projected fund withdrawal intervals for the associated closure costs from the approved financial assurance instrument*
14. *Landfills shall be closed by:*
- A. *Leveling the waste*
  - B. *Covering the waste with a minimum of 2 feet of cover soil, including 6-inches of topsoil.*
  - C. *Contouring the cover to minimum 2 percent surface slopes and maximum 33 percent side slopes, except where integrity and erosion control can be demonstrated at steeper slopes.*
15. *Notify the UDEQ Executive Secretary of the intent to implement the closure plan in whole or part, 60 days prior to the project final receipt of waste at the unit or facility.*
16. *Commence implementation of the closure plan, in part or whole, within 30 days after final elevation is attained in part or all of the facility closure plan. Closure activities shall be completed within 180 days from their starting time.*
17. *Within 90 days following completion of closure, submit to the UDEQ Executive Secretary the following:*
- A. *Facility or unit closure plan sheets signed by a professional engineer registered with the state of Utah, and modified as necessary to represent as-built changes to final closure construction as approved in the closure plan*
  - B. *Certification by the owner or operator and a professional engineer registered in the state of Utah that the site or unit has been closed in accordance with the approved closure plan.*
18. *Provide post-closure activities for facility maintenance and monitoring of gases, land, and water for 30 years or as long as the UDEQ Executive Secretary determine is necessary for the facility to become stabilized and to protect human health and the environment.*

19. *Develop, keep on file, and abide by a post-closure plan. The post-closure plan shall project time intervals at which post-closure activities are to be implemented and identify post-closure cost estimates and project fund withdrawal intervals from the selected financial assurance instrument.*
20. *Commence post-closure activities after closure activities have been completed.*
21. *Submit a certification to the UDEQ Executive Secretary when post-closure activities are complete, signed by the owner or operator and a professional engineer registered in the state of Utah stating why post-closure activities are no longer necessary.*

The Huntington Plant will continue to remain in compliance with the rules and regulations stated in this section throughout the life of the landfill. A complete copy of the Huntington Plant *Landfill Operation Plan* is located in Appendix E.

#### **2.2.14 Additional Site Information (R315-302-2(2)(o))**

Additional site specific information concerning the landfill may be requested by the Utah DSHW. If this situation occurs, PacifiCorp will supply the information to the DSHW as soon as practicable.

### **3.0 PART III – TECHNICAL REPORT**

#### **3.1 MAPS**

##### **3.1.1 Topographic Map (R315-310-4(2)(a)(i))**

Plan Sheet 1(USGS Topographic Map) also shows a topographic map of the landfill and surrounding area. Plan Sheet 4 (Final Grading Plan) shows the final contours of the closed landfill.

##### **3.1.2 U.S.G.S. Topographic Map (R315-310-4(2)(a)(ii))**

The most recent USGS Map 7 ½ minute series topographic map is included as Plan Sheet 1, showing the waste facility boundary, property boundary, existing utilities and structures within ¼ - mile of the site, and the direction of prevailing winds.

#### **3.2 ENGINEERING REPORT**

##### **3.2.1 Landfill Design & Operation Details (R315-310-3(1)(b))**

This section addresses cell design, cover design, fill methods, and elevation of the final cover, including plans and drawings.

##### ***Landfill Phasing***

The total permitted area of the industrial waste landfill is 8.07 acres; however, only 2.85 acres is proposed for active waste disposal. The current active industrial waste area will provide approximately 20 years of plant industrial waste capacity. The industrial landfill will be closed in the year 2027. The final closed landfill surface is shown in Plan Sheet 6 (Figure 4).

##### ***Industrial Wastes***

Industrial wastes will be disposed of within the boundary of the industrial waste landfill, as shown in Plan Sheet 4. Waste materials should be compacted to the smallest practical volume during placement in the landfill. After reducing the volume of waste, the materials should be covered with at least 6 inches of compacted fly or bottom ash and then a thin veneer of pyrites or bottom ash by the end of each day that waste is deposited in the landfill. The wastes should be shaped so that water does not pond on top of the wastes

##### ***Final Cover System***

The recommended cover system for the industrial waste area is 2 feet of cover soil, including an 18-inch compacted infiltration layer and a 6-inch layer of topsoil. The cover surface should be graded in accordance with the Final Grading Plan shown in Plan Sheet 4. The topsoil cover should then be fertilized and seeded to promote the growth of vegetation that will minimize erosion.

### **3.2.2 Run-Off/Run-On Control Systems (R315-310-5(2)(b))**

Operation of the industrial landfill will be conducted in a manner that will minimize the amount of storm water run-on and runoff that contacts the waste. As waste is placed in the landfill, application of daily cover will minimize the amount of water contacting the waste. The working area will be sloped to promote drainage away from the waste, and berms will be installed to prevent run on water from contacting the waste, and also to prevent any water that has contacted the waste from leaving the active landfill area. The area surrounding the industrial landfill will be graded such that precipitation is transmitted away from the active landfill area. To promote runoff, as opposed to infiltration of rainfall into the wastes, the waste surface should be sloped at a minimum of 2 percent to the edges of the landfill.

### **3.3 CLOSURE PLAN (R315-310-3(1)(h) and R315-310-5(2)(c))**

#### **3.3.1 Closure Schedule (R315-310-4(2)(d)(i))**

The industrial landfill will be closed in 2027, as detailed in this document.

#### **3.3.2 Final Cover Design (R315-310-4(2)(c)(iii) and R315-305-5(5))**

The regulations for final cover systems for industrial landfills in Utah consist of 2 feet of soil cover including 6 inches of topsoil to support vegetative cover. The recommended cover system for the industrial waste landfill is 18 inches of borrow cover soil and 6 inches of topsoil, for a total of 24 inches. The current cover design specifies that the 24-inch soil cover will be purchased from an off-site source. The first 18-inches of cover will be compacted to a permeability of no less than  $1 \times 10^{-5}$  cm/sec. Hay mulch from the plant's research farm will be incorporated into the top 6-inches of soil to promote vegetation growth.

The cover systems will be fertilized and seeded to promote the growth of vegetation that will minimize erosion and maintenance requirements for the cover system. Specific seeding and fertilizing recommendations are summarized in the Landfill Closure section of the *Landfill Operations Plan*, located in Appendix D.

#### **3.3.3 Site Capacity (R315-310-4(2)(d)(ii))**

The plant industrial waste site has been designated within a central area of the top of the old ash landfill. Based on an average volume of 1600 cubic yards of waste per year, the current industrial waste area will provide capacity until 2027.

#### **3.3.4 Final Regulatory Inspection (R315-310-4(2)(d)(iii))**

After all closure operations are complete, a final inspection will be conducted by the appropriate regulatory agencies.

### **3.4 POST – CLOSURE CARE PLAN (R315-310-3(1)(h))**

#### **3.4.1 Site Monitoring (R315-310-4(2)(e)(i))**

The facility will be inspected quarterly for evidence of run-on, erosion of the final cover, and ponding of water on the final cover. Appropriate actions to correct these conditions will be undertaken and may include construction of drainage ditches or diversion dikes to prevent run-on, repair of erosion damage, as well as repair and grading of areas of ponding water on the final cover.

The facility will be inspected quarterly for areas of poor vegetative cover. Such areas will be prepared and reseeded in order to establish adequate vegetative cover. Annual fertilization of the facility will be undertaken at least until the vegetative cover is established sufficiently to render such maintenance unnecessary.

Storm water and erosion control features will be maintained until the vegetative cover is established sufficiently to render such maintenance unnecessary. Berms and drainage ditches will be inspected quarterly for evidence of damage restricted flow caused by erosion or sedimentation. Such blockages will be removed expeditiously.

#### **3.4.2 Title and Land Use Changes/Zoning Restrictions (R315-310-4(2)(e)(ii))**

At this time, the anticipated land use following closure is wildlife habitat. Any alternative land uses will be submitted to the department for approval prior to initiation of construction or development.

A sample deed notice is outlined below:

**CAUTION! THE PROPERTY MORE COMPLETELY DESCRIBED BELOW HAS BEEN USED FOR AN INDUSTRIAL SOLID WASTE DISPOSAL FACILITY. THE COMPLETE LEGAL DESCRIPTION IS:**

“Beginning at a point which is S 0° 07’ 50” W, 697.86 feet and N 89° 52’ 10” W, 1149.00 feet from the Northeast corner of the Southeast quarter of Section 1, T. 17 S., R. 7 E., Salt Lake Meridian, Utah; Thence S 60° 28’ 19” W, 864.69 feet; Thence S 55° 17’ 26” E, 553.10 feet; Thence N 59° 06’ 10” E, 563.39 feet; Thence N 22° 20’ 53” W, 488.50 feet to the point of beginning.

Containing 8.068 acres m/l.

Basis of Bearing: S 0° 07’ 50” W between the East Quarter Corner of Section 1, T. 17 S., R. 7 E. SLM and the South Sixteenth Corner of Section 6, T. 17 S., R. 8 E. SLM, as determined by GPS observations. Both corners being monumented with 1982 BLM caps.”

DISPOSED MATERIALS INCLUDE SCRAP METAL, WOOD, PAPER, DEMOLITION WASTE, PLASTIC PRODUCTS, FOOD SCRAPS, AND MISCELLANEOUS PLANT INDUSTRIAL WASTE.

Any changes to the record of title, land use, or zoning restrictions will be submitted to the department for approval prior to construction or development.

#### **3.4.3 Post-Closure Maintenance (R315-310-4(2)(e)(iii))**

PacifiCorp will maintain the approved final contours and drainage system of the site to minimize precipitation run-on, minimize erosion, optimize drainage of precipitation, and provide a surface drainage system, which in no way adversely affects proper drainage from adjacent lands. The facility will be inspected quarterly for evidence of run-on, erosion of the final cover, and ponding of water on the final cover. Appropriate actions to correct these conditions will be undertaken and may include construction of drainage ditches or diversion dikes to prevent run-on, repair of erosion damage, as well as repair and grading of areas of ponding water on the final cover.

PacifiCorp will assure that a healthy vegetative cover is established and maintained over the site. The facility will be inspected quarterly for areas of poor vegetative cover. Such areas will be prepared and reseeded in order to establish adequate vegetative cover. Annual fertilization of the facility will be undertaken at least until the vegetative cover is established sufficiently to render such maintenance unnecessary.

Storm water and erosion control features will be maintained throughout the post-closure period, or until such maintenance is determined unnecessary. Berms and drainage ditches will be inspected quarterly for evidence of damage or restricted flow caused by erosion or sedimentation. Such blockages will be removed expeditiously.

#### **3.4.4 Contact Information (R315-310-4(2)(e)(vi))**

The primary contact for the Huntington Landfill is listed below:

<b>NAME</b>	Darce Guymon
<b>MAILING ADDRESS</b>	P.O. Box 680 Huntington, UT 84528-0000
<b>PHYSICAL ADDRESS</b>	Hwy 31 W. of Huntington City Huntington, UT
<b>TELEPHONE NUMBER</b>	435-687-4305

#### **3.5 FINANCIAL ASSURANCE (R315-310-3(1)(j))**

PacifiCorp has developed Closure and Post-Closure cost estimates for the Huntington Industrial Solid Waste Landfill, pursuant to Utah DSHW regulations and associated guidance documents. Estimates are provided for a third-party to conduct and complete closure activities.

### **3.5.1 Closure Cost Calculations (R315-310-4(2)(d)(iv))**

Closure costs were calculated, in current dollars, for a third party to conduct and complete closure activities at the landfill. A Landfill Closure Cost Estimate Worksheet was developed using the Utah DSHW *Preparation of Solid Waste Facility Closure and Post-Closure Cost Estimates* Guidance Document. The total closure cost for the Huntington Industrial Waste Landfill is **\$198,284.35**. The worksheet is included in Appendix F, along with detailed reference information and assumptions used to develop the costs.

### **3.5.2 Post-Closure Cost Calculations (R315-310-4(2)(e)(iv))**

Post-closure costs were calculated, in current dollars, for a third party to conduct and complete post-closure activities at the landfill. The post-closure period was estimated at thirty years. A Landfill Post-Closure Cost Estimate Worksheet was developed using the Utah DSHW *Preparation of Solid Waste Facility Closure and Post-Closure Cost Estimates* Guidance Document. The total post-closure cost for the Huntington Industrial Waste Landfill is **\$318,875.59**. The worksheet is included in Appendix F, along with detailed reference information and assumptions used to develop the costs.

### **3.5.3 Financial Assurance Mechanism (R315-309-1(1))**

A corporate financial test agreed upon between PacifiCorp and the Utah DSHW will be used to ensure that closure and post-closure activities are completed. Financial assurance information is located in Appendix G.

## **4.0 REFERENCES**

Huntington Power Plant, *Landfill Operations Manual*.

Huntington Power Plant, *Plant Emergency Procedures (HTG-SAF-002)*.

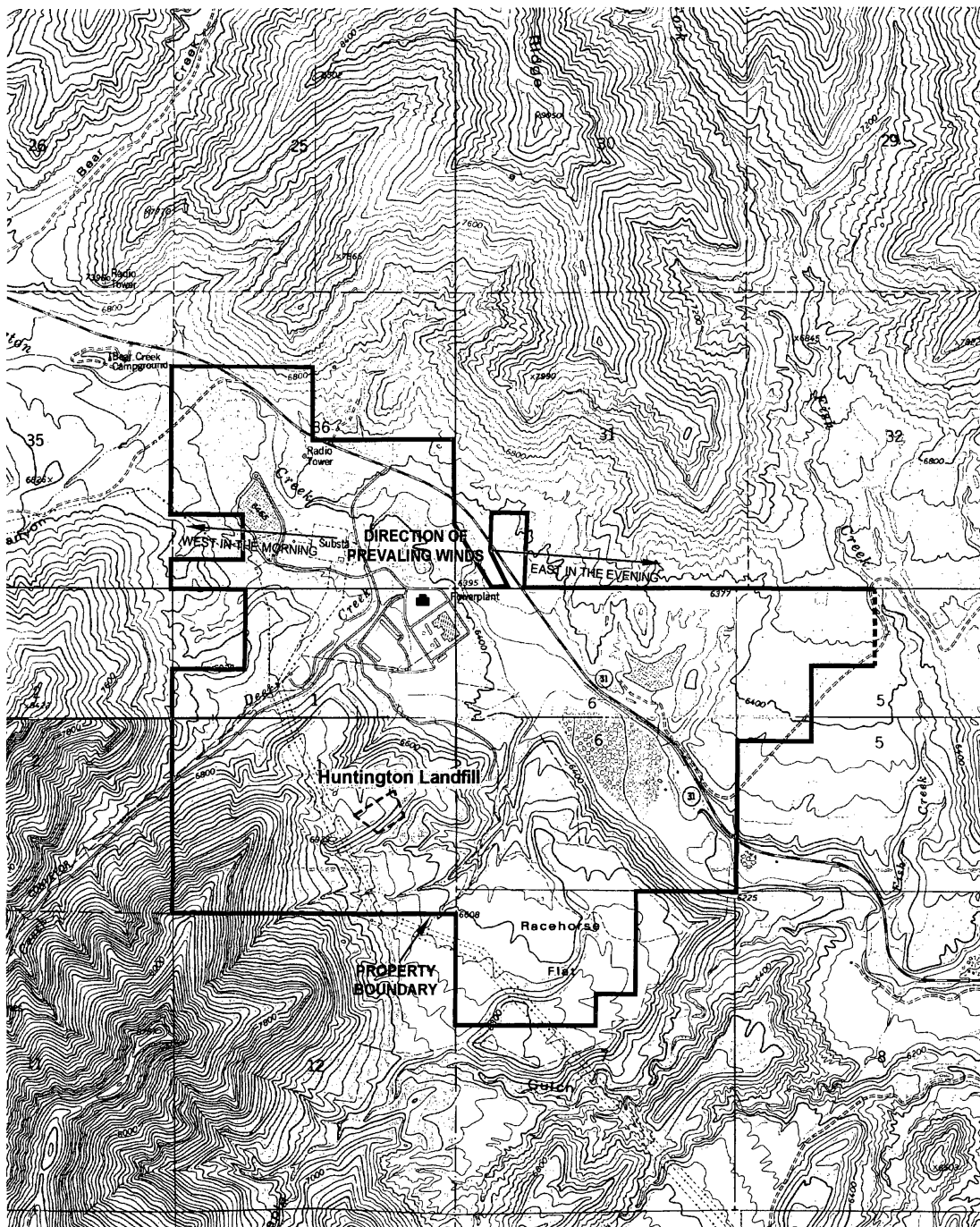
Utah Division of Solid and Hazardous Waste, *Solid Waste Rules (Section R315-301 through 320)*.

Utah Division of Solid & Hazardous Waste-Solid Waste Program, Various Guidance Documents

Discussions with PacifiCorp personnel.

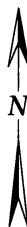
## LIST OF PLAN SHEETS

Plan Sheet 1	USGS Topographic Map
Plan Sheet 2	Zoning Map
Plan Sheet 3	Huntington Industrial Waste Landfill – Site Map
Plan Sheet 4	Final Landfill Grading Plan
Plan Sheet 5	Industrial Waste Landfill – Typical Operation
Plan Sheet 6	Typical Industrial Waste Cross Section



### Legend

- PacificCorp Property Boundary
- - - - - Landfill Boundary



SCALE IN FEET



### NOTES:

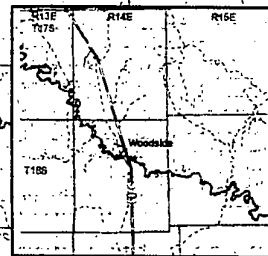
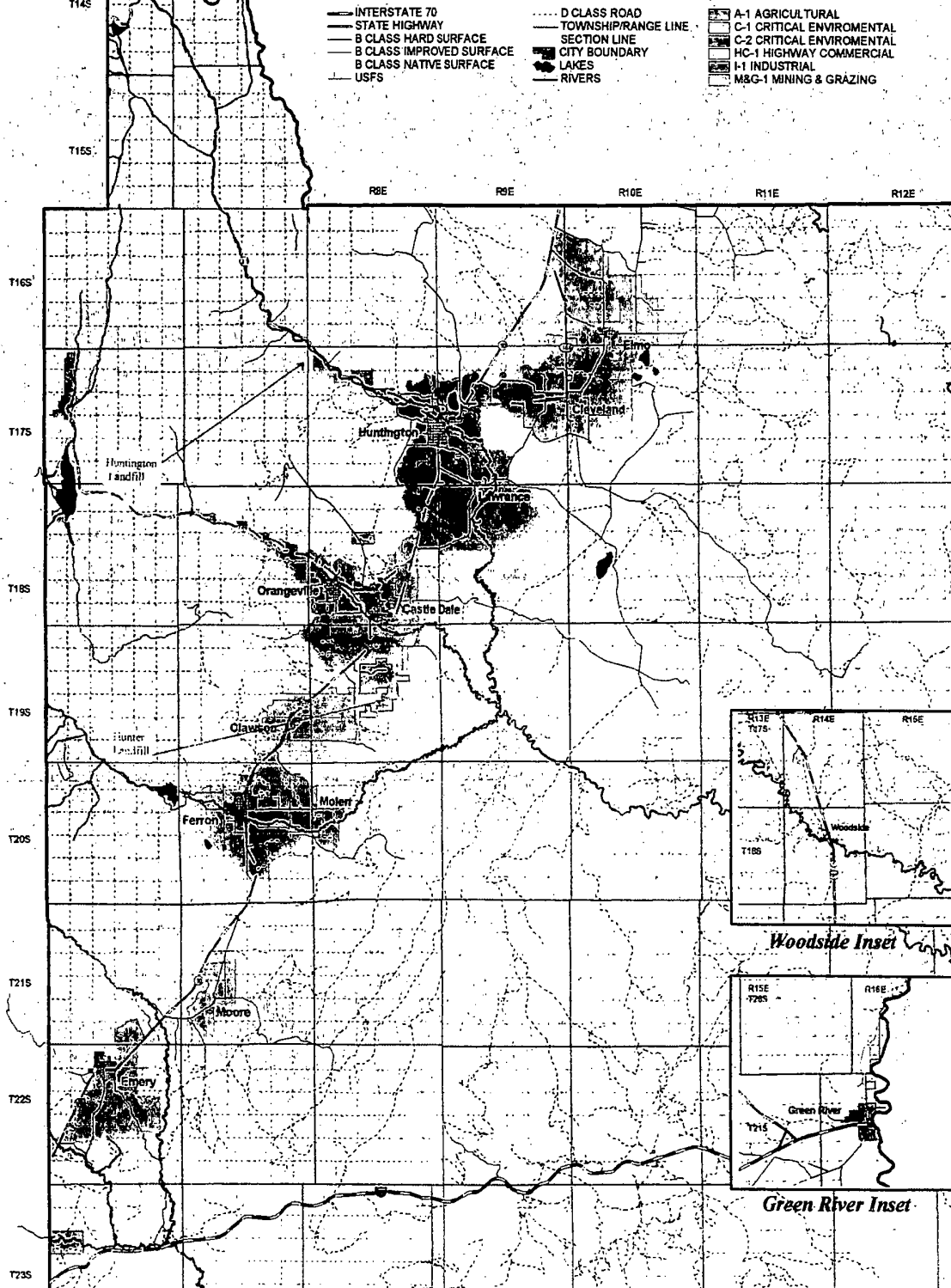
Disclaimer: PacificCorp makes no warranty as to the accuracy, reliability, or completeness of this data for individual or aggregate use with other data.

Map Source: This map was created by PowerMap, a PacificCorp internal application utilizing ESRI's arcIMS technology.

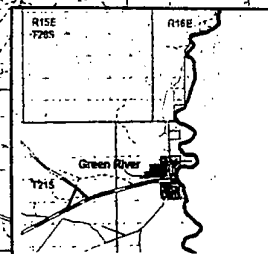
PowerMap URL: <http://powermap.pacificcorp.com>

 <b>WATER &amp; ENVIRONMENTAL TECHNOLOGIES, PC</b>	
 <b>PACIFICCORP ENERGY</b>	<b>HUNTINGTON POWER PLANT</b>
<b>HUNTINGTON LANDFILL USGS TOPOGRAPHIC MAP</b>	
HNTG-B1 DATE: 6/12/06	<b>PLAN SHEET 1</b>

# Emery County ZONING BOUNDARIES



Woodside Inset



Green River Inset

## Unofficial Zoning Map

Revised 2007  
Adopted by: \_\_\_\_\_  
Chairman Board of Commissioners  
County Clerk

6	5	4	3	2	1
7	8	9	10	11	12
13	14	15	16	17	18
19	20	21	22	23	24
25	26	27	28	29	30
31	32	33	34	35	36

Section Numbering System



2 0 2 4 Miles

**EMERY**  
COUNTY  
GIS DEPARTMENT  
For further information contact  
Bryant Anderson (435)381-5576  
95 East Main Street  
Castle Dale, UT 84513  
bryant@emery.ut.us



## LEGEND

- = Active Waste Area
- = Industrial Waste Permit Boundary

Reference: Digital Orthophotographs of the Hiawatha & Red Point, Utah USGS Quadrangles. Date of photography October 5, 1997.



SCALE IN FEET

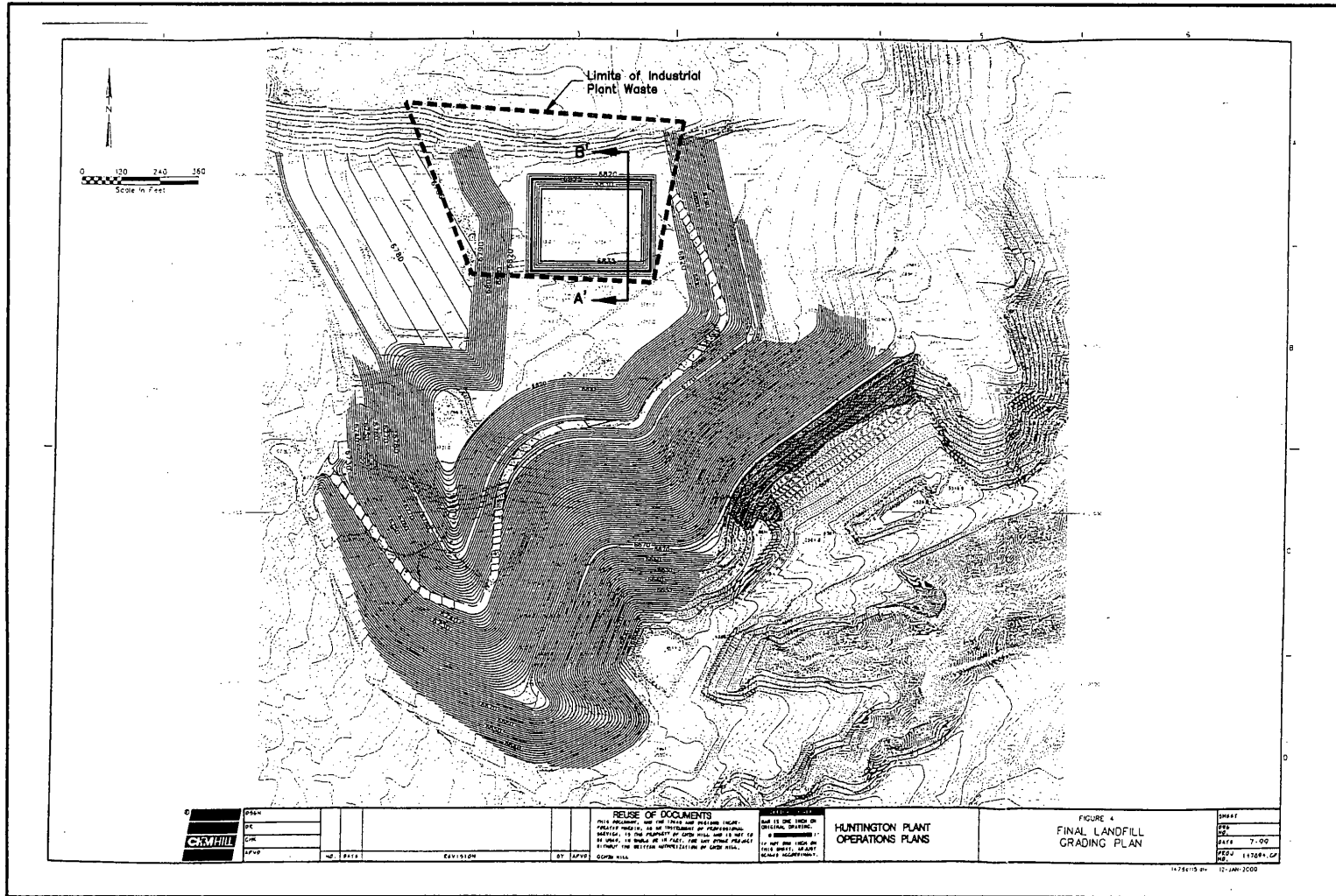


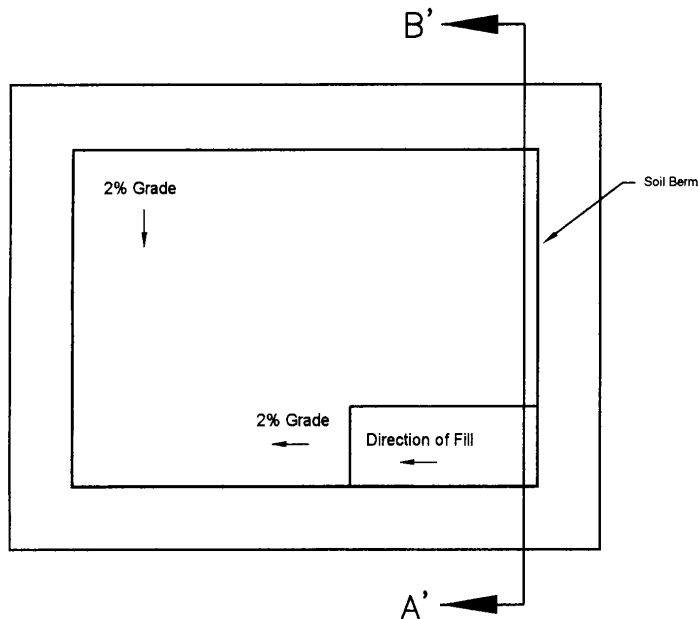
**PACIFICORP ENERGY** HUNTINGTON POWER PLANT

**SITE  
MAP**

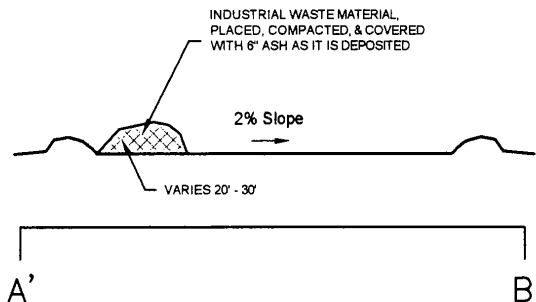
HUNTINGTONBASE  
DATE: 6/16/06

**PLAN SHEET 3**





**PLAN VIEW**

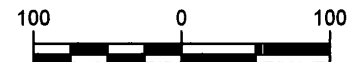


**PROFILE VIEW**

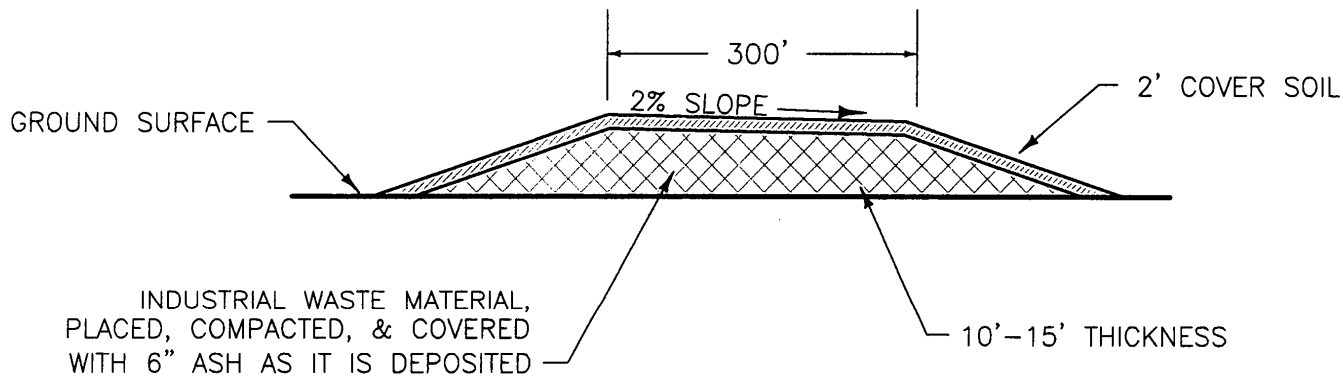
**NOTES:**

1. Runoff is routed away from the waste to the Southwest corner of the landfill.
2. Waste is currently being placed in the Southeast corner of the site and move in a Westerly direction along the slope to the Western boundary. Waste will then be placed in an Easterly direction and the process will repeat itself, moving from South to North.
3. Profile View not drawn to scale. Plan View scale is 1" = 100'.

SCALE IN FEET



	HUNTINGTON POWER PLANT
INDUSTRIAL WASTE LANDFILL TYPICAL OPERATION	
HuntingtonLandfillOp DATE: 6/1/06	<b>PLAN SHEET</b> <b>5</b>



NOT TO SCALE

<b>WATER &amp; ENVIRONMENTAL TECHNOLOGIES, PC</b>	
<b>PACIFICORP ENERGY</b> <small>A DIVISION OF PACORP</small>	<b>HUNTINGTON POWER PLANT</b>
<b>TYPICAL INDUSTRIAL WASTE CROSS-SECTION</b>	
HNTG-CRS-SEC DATE: 6/1/06	<b>PLAN SHEET 6</b>

**Appendix A.**  
**Permit Application Form**

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY

DIVISION OF SOLID AND HAZARDOUS WASTE

APPLICATION FOR A PERMIT TO OPERATE A CLASS III LANDFILL

The applicant shall submit an original permit application, which includes a general report and a technical report, to:

Dennis R. Downs, Director  
Division of Solid and Hazardous Waste  
Utah Department of Environmental Quality  
PO Box 144880  
Salt Lake City, Utah 84114 - 4880

(Note: When the application is determined to be complete, submittal of the original complete permit application and one copy of the complete application will be required.)

PART I - GENERAL INFORMATION

1. Name of Facility Huntington Plant
2. Site Location Highway 31 West of Huntington
3. Facility Owner PacifiCorp Energy
4. Facility Operator PacifiCorp Energy
5. Contact Person Kerry Powell

Address P.O. Box 680

Huntington, UT 84528

Telephone (435) 687-4331

6. Type of Facility:

☐

Class IIIa Landfill

☒

Class IIIb Landfill

7. Type of Application

☒

Initial Application

☐

Permit Renew

## 8. Property Ownership

- ☒ Presently owned by applicant  
☐ To be purchased by applicant  
☐ To be leased by applicant

**Property owner (if different from applicant)**

Name \_\_\_\_\_

**Address** \_\_\_\_\_

Telephone \_\_\_\_\_

9. Certification of submitted information.

(Name of Official)

(Title)

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

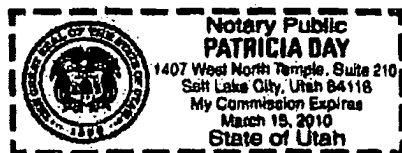
Signature: Patricia Way Date 7/10/06

SUBSCRIBED AND SWORN to before This 10<sup>th</sup> day of July, 20 06

My commission expires on the 3<sup>rd</sup> day of March, 2010

Notary Public in and for

(SEAL) \_\_\_\_\_ County, Utah.



**Important Note:** The following checklist is for the permit application and addresses only the requirements of the Division of Solid and Hazardous Waste. Other federal, state, or local agencies may have requirements that the facility must meet. The applicant is responsible to be informed of, and meet, any applicable requirements. Examples of these requirements may include obtaining a conditional use permit, a business license, or a storm water permit. The applicant is reminded that obtaining a permit under the *Solid Waste Permitting and Management Rules* does not exempt the facility from these other requirements.

An application for a permit to construct and operate a landfill is the documentation that the landfill will be located, designed, constructed, and operated to meet the requirements of Rules R315-302, R315-303, R315-308, R315-309, and R315-315 of the *Utah Solid Waste Permitting and Management Rules* and the *Utah Solid and Hazardous Waste Act* (UCA 19-6-101 through 123). The application should be written to be understandable by regulatory agencies, landfill operators, and the general public. The application should also be written so that the landfill operator, after reading it, will be able to operate the landfill according to the requirements with a minimum of additional training.

Copies of the *Solid Waste Permitting and Management Rules*, the *Utah Solid and Hazardous Waste Act*, along with many other useful guidance documents can be obtained by contacting the Division of Solid and Hazardous Waste at 801-538-6170. Most of these documents are available on the Division's web page at [www.eq.stat.ut.us/eqshw/dshw-1.htm](http://www.eq.stat.ut.us/eqshw/dshw-1.htm). Guidance documents can be found at the solid waste section portion of the web page.

When the application is determined to be complete, the original complete application and one copy of the complete application are required along with an electronic copy.

### **CHECKLIST OF ADDITIONAL INFORMATION REQUIRED**

(Please see Section R315-310-5 of the *Utah Solid Waste Permitting and Management Rules*)

## **PART II - GENERAL REPORT**

### INTRODUCTION

- ☒ Completed PART I - GENERAL INFORMATION (R315-310-3(1)(a))
- ☒ General description of the facility (R315-310-3(1)(b))
- ☒ Legal description; proof of ownership, lease agreement, or other mechanism; latitude and longitude of the site; and land use and zoning of surrounding area (R315-310-3(1)(c))

☒ The types of waste and area served by the facility (R315-310-3(1)(d))

☒ A demonstration that the landfill is not a commercial landfill

PLAN OF OPERATION (R315-310-3(1)(e))

☒ An intended schedule of construction (R315-302-2(2)(a))

☒ A description of on-site waste handling procedures and an example of the form that will be used to record the weights or volumes of waste received (R315-302-2(2)(b) and R315-310-3(1)(f))

☒ A schedule for conducting inspections and monitoring and examples of the forms used to record the results of the inspections and monitoring (R315-302-2(2)(c) , R315-302-2(5)(a), and R315-310-3(1)(g))

☒ Contingency plans in the event of a fire or explosion (R315-302-2(2)(d))

☒ Corrective action programs to be initiated if ground water is contaminated (R315-302-2(2)(e))

☒ Contingency plans for other releases, e.g. explosive gases or failure of run-off collection system (R315-302-2(2)(f))

☒ A plan to control fugitive dust generated from roads, construction, general operations, and covering the waste (R315-302-2(g))

☒ Description of maintenance of installed equipment (R315-302-2(2)(h))

☒ Procedures for excluding the receipt of Regulated hazardous or PCB containing waste (R315-302-2(2)(i))

☒ Procedures for controlling disease vectors (R315-302-2(2)(j))

☒ A plan for alternative waste handling (R315-302-2(2)(k))

☒ A general training and safety plan for site operations (R315-302-2(2)(n))

☒ Any other items not covered above as to how the facility will meet the requirements of Rule R315-304 (R315-310-5(2)(e))

☒ Any other site specific information pertaining to the plan of operation required by the Executive Secretary (R315-302-2(2)(o))

### PART III TECHNICAL REPORT

#### MAPS

- ☒ Topographic map drawn to the required scale and contours showing the boundaries of the landfill unit; design and location of the run-on/run-off control structures; and the borrow and fill areas (R315-310-4(2)(a)(i))
- ☒ Most recent U.S. Geological Survey topographic map, 7-1/2 minute series, showing the waste facility boundary; the property boundary; surface drainage channels; existing utilities and structures within one-fourth mile of the site; and the direction of the prevailing winds (R315-310-4(2)(a)(ii))

#### ENGINEERING REPORT - PLANS, SPECIFICATIONS, AND CALCULATIONS

- ☒ Cell design, cover design, fill methods, elevation of final cover including plans and drawings (R315-310-3(1)(b))
- ☒ Design and location of run-on and run-off control systems (R315-310-5(2)(b))

#### CLOSURE PLAN (R315-310-3(1)(h) and R315-310-5(2)(c))

- ☒ Closure schedule (R315-310-4(2)(d)(i))
- ☒ Design of final cover (R315-310-4(2)(c)(iii) and R315-305-5(5))
- ☒ Capacity of site in volume and tonnage (R315-310-4(2)(d)(ii))
- ☒ Final inspection by regulatory agencies (R315-310-4(2)(d)(iii))

#### POST-CLOSURE CARE PLAN (R315-310-3(1)(h))

- ☒ Site monitoring, if required (R315-310-4(2)(e)(i))
- ☒ Changes to record of title, land use, and zoning restrictions (R315-310-4(2)(e)(ii))
- ☒ Maintenance activities to maintain cover and run-on/run-off control systems (R315-310-4(2)(e)(iii))
- ☒ List the name, address, and telephone number of the person or office to contact about the

facility during the post-closure care period (R315-310-4(2)(e)(vi))

FINANCIAL ASSURANCE (R315-310-3(1)(j))

- ☒ Identification of closure costs including cost calculations (R315-310-4(2)(d)(iv))
- ☒ Identification of post-closure care costs including cost calculations (R315-310-4(2)(e)(iv))
- ☒ Identification of the financial assurance mechanism that meets the requirements of Rule R315-309 and the date the mechanism will become effective (R315-309-1(1))

SPECIAL REQUIREMENTS FOR A CLASS IIIa LANDFILL (R315-304-5(7)(b))

- ☐ A geohydrological assessment of the site (R315-310-4(2)(b))
- ☐ An engineering report, plans, specifications, and calculations (R315-310-4(2)(c))
- ☐ A ground water monitoring plan (R315-304-5(4) and R315-310-4(2)(c)(vi))
- ☐ A closure plan that meets the requirements of R315-303-3(4) (R315-304-5(2)(a))

Revision date February 21, 2002

**Appendix B.**  
**Proof of Ownership Documents**

WARRANTY DEED

The State of Utah; Department of Natural Resources, Division of Fish and Game of 1596 West North Temple, Salt Lake City, Utah, Grantors, hereby CONVEY AND WARRANTS to Utah Power and Light Company of 1407 West North Temple, Salt Lake City, Utah, for the sum of ten dollars and other valuable considerations provided in agreement #5399, the following described land in Emery County, State of Utah, to wit:

All of Section 1, T. 17 S., R. 7 E., S.L.M., excepting therefrom Lot 5, and consisting of 659.26 acres more or less. Also SE $\frac{1}{4}$  SW $\frac{1}{4}$ ; SW $\frac{1}{4}$  SE $\frac{1}{4}$ ; E $\frac{1}{2}$  SE $\frac{1}{4}$ ; NW $\frac{1}{4}$  SE $\frac{1}{4}$ ; N $\frac{1}{2}$  SW $\frac{1}{4}$ ; S $\frac{1}{2}$  NW $\frac{1}{4}$ ; Section 36, T. 16 S., R. 7 E., S.L.M., excepting 4.29 acres previously conveyed to Utah State Road Commission, and comprising 355.71 acres more or less.

Total 1,014.97 acres more or less.

No mineral or water transferred.

WITNESS the hands of said Grantors this 26 day of April AD 1971.

Utah State Division  
of Fish and Game

*John E. Phelps*  
John E. Phelps, Director

STATE OF UTAH )  
COUNTY OF SALT LAKE ) ss

On the 26 day of April 1971, personally appeared before me John E. Phelps who duly acknowledged to me that he is Director of the State of Utah, Division of Fish and Game, and that he is authorized to execute the foregoing instrument for and in behalf of said Division and that he did so execute said instrument for and in behalf of the Division of his own free will.

My commission expires:

July 5, 1974

Residing in County of Utah

*Charles H. [Signature]*  
Notary Public

STATE OF UTAH  
COUNTY OF SALT LAKE  
FILED  
MAY 5 4 24 PM '71  
66116.66  
COUNTY RECORDER

211075 2.50

**Appendix C.**  
**Landfill Inspection Forms**

## Random Inspection Report Form

Inspector: \_\_\_\_\_

Date: \_\_\_\_\_Time: \_\_\_\_\_

**Signature::**

<b>Facility:</b>	Huntington Power Plant, Industrial Waste Landfill Box 680 Huntington, Utah 84528
------------------	--

Type:	Class IIIb Industrial Waste Landfill
-------	--------------------------------------

Weights & Measures (Taken from Report of Driver)		
1	Weight of Load	lbs
2	Estimate of Uncompacted Volume of Load	Cu yds

Brief Description of Contents of Load
(Example: Waste Paper, Cardboard, Pallets, Pigs, Plastic, Used Rags, Empty drums, Empty buckets, Punctured aerosol cans, Floor sweepings. <b>List what you see</b> in this load.)

<p><b>Prohibited Materials - list and <u>remove</u> any you see:</b></p> <p>(example: Non-punctured aerosol cans, drums or buckets partially full, any liquid waste, mercury, fluorescent bulbs <u>without</u> green ends, lead acid batteries, NiCad batteries, any hazardous or PCB-containing wastes must be separated and removed from this site.)</p>
<p>Please place prohibited materials removed from the landfill in the plastic drum near the gate. Thank you.</p>

A minimum of 1% of incoming loads will be spread on the ground to allow visual inspection by an inspector other than the contracted drivers. This form is used to record those inspections and becomes a part of the operating record.

# INDUSTRIAL WASTE LANDFILL TRAINING SIGN-IN SHEET

DATE: \_\_\_\_\_

GROUP: \_\_\_\_\_

DESCRIPTION OF TRAINING:

INSTRUCTOR: \_\_\_\_\_

Huntington Power Plant Industrial Waste Landfill - Operations Plan

LENGTH OF TRAINING: \_\_\_\_\_

☐ Utah Administrative Code  
Regulation R315-304 as it applies  
to Class IIIb landfills

☐ Solid Waste Handling Procedures

☐ Inspections and Monitoring

☐ Random Inspection Requirements

☐ Contingency Plans in the event of Fire or Explosion

☐ Storm Water Pollution Prevention Plan

☐ Fugitive Dust Control Plan

☐ Procedures for Exclusion of  
Hazardous Waste and of waste  
containing PCBs

☐ General Training and Safety for Site Operators

☐ Logs of Weight, Volume and Classification of wastes

☐ Cell Design and Cover Requirements

☐ Site Access Control

☐ Other \_\_\_\_\_

EMPLOYEE / CONTRACTOR	EMPLOYEE NUMBER	EMPLOYEE / CONTRACTOR	EMPLOYEE NUMBER
01.		16.	
02.		17.	
03.		18.	
04.		19.	
05.		20.	
06.		21.	
07.		22.	
08.		23.	
09.		24.	
10.		25.	
11.		26.	
12.		27.	
13.		28.	
14.		29.	
15.		30.	

*I certify that the employees / contractors listed above were presented the training listed hereon.*

Supervisor Signature: \_\_\_\_\_

Date: \_\_\_\_\_

Comments: \_\_\_\_\_

Please fill out a "Training Sign-in Sheet" for **all** training, and forward to the Administrative Assistant

Thanks!

**Monthly Landfill Inspection  
Huntington Plant**

Yes	No	Inspection Item	Comments (Describe the data and nature of any repairs or corrective action, include WO numbers)
		Are barriers in place to prevent unauthorized access?	
		Are signs in place that identify the name of the facility, unacceptable materials, and an emergency number to call?	
		Is there a fire extinguisher present?	
		Is there evidence that rats or other animals have infested the area?	
		Is the trash being dumped in a concise and compact area according to the operating plan?	
		Is the trash covered sufficiently such that there is no loose trash and that combustible material has at least six inches of cover?	
		Is there evidence that improper waste has been dumped (liquids, unpunctured aerosol cans, unsmashed drums, etc.)?	
		Is fugitive dust observed at the facility or on the road to the facility?	
		Is the waste log located at the site with proper and complete entries?	
		Is there evidence that storm water has been released from the facility?	

Inspector \_\_\_\_\_ (Print) \_\_\_\_\_ (Sign) Date \_\_\_\_\_ Time \_\_\_\_\_

## Log Sheet

<b>Driver:</b>		
	Print Name	Signature
<b>Date:</b>		
<b>Time:</b>		
<b>Vehicle Number:</b>		

Weights & Measures	
Weight of Truck & Load	<input type="text"/> lbs
Weight of Empty Truck (Tare)	<input type="text"/> lbs
1 Weight of Load	<input type="text"/> lbs
2 Estimate of Uncompacted Volume of Load	<input type="text"/> Cu yds

(example: The 20 foot bin level full = 26 cu yds, 3/4 full = 19.5 cu yds, 1/2 full = 13 cu yds, 1/4 full = 6.5 cu yds)

[illegible]

**Prohibited Materials - list and remove any you see:**

(example: Non-punctured aerosol cans, drums or buckets partially full, any liquid waste, mercury, flourescent bulbs without green ends, lead acid batteries, NiCad batteries, any hazardous or PCB-containing wastes must be separated and removed from this site.)

Please place prohibited materials removed from the landfill in the plastic drum near the gate. Thank you.

**Appendix D.**  
**Huntington Power Plant Landfill Operations Plan**

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- 1      Huntington Industrial Waste Landfill - Site Map
- 2      Final Landfill Grading Plan
- 3      Industrial Waste Landfill - Typical Operation
- 4      Typical Industrial Waste Cross Section

## Introduction

The Huntington Plant is a coal-fired electrical generation plant owned and operated by PacifiCorp and located near Huntington, Utah. The Huntington Plant disposes of industrial wastes at its designated industrial landfill site located near the power plant facility. The industrial landfill has an expected life through 2027.

This *Landfill Operations Plan* describes the physical characteristics of the site, as well as details and procedures for industrial waste disposal, remaining development of the industrial landfill, site drainage and storm water control, and closure and post-closure of the industrial landfill.

## Existing Site Operations

The Huntington Power Plant produces the following wastes associated with the electric generation operations: pyrites, slaker grit, fly ash, bottom ash, and scrubber sludges. These wastes are disposed of in the new ash landfill.

In addition, non-combustion wastes from dredging ponds and basins, sludges from sumps and vessels, and plant industrial wastes are generated and disposed of at the industrial landfill. The industrial landfill is a specific area of the original ash landfill and is subject to the conditions of an industrial waste permit issued by the State of Utah.

The hauling and placement of wastes is contracted to a third party trucking company, who provides the equipment and labor necessary to haul, place, and compact the wastes in the industrial landfill. An existing gravel road is the primary access road from the power plant to the landfill. Industrial wastes are placed in the designated industrial landfill area shown in the topographic map in Plan Sheet 1, and covered with ash each day.

## Environmental Site Conditions

The environmental site conditions discussed below include a description of the general landfill area and general site drainage conditions.

The industrial waste landfill is located near the Huntington Power Plant in Emery County, Utah. The total permitted landfill area is approximately 8.07 acres; however, only 2.85 acres is currently proposed for active waste disposal. The permit boundary and active industrial waste area to be filled is shown in Plan Sheet 4. The existing terrain has slopes that vary from 3:1 (horizontal:vertical) to approximately 10:1 (h:v). The predominant slope is approximately 10:1 (h:v). The surface soils in the vicinity are alluvial fans of well drained calcareous soils that are medium textured silt, sand, and cobbles. Formations of limestone, sandstone, siltstone, shale conglomerate and coal are at varying depths below the surface, but no greater than 50 feet.

Average precipitation is between 6 and 10 inches per year, with the main season of rainfall occurring in late July through October. 10 to 20 inches of snow can be expected in the winter, representing between one and two inches of the annual precipitation. Skies are clear

about 225 days per year. Winds are light to moderate in all seasons, generally blowing from the east in the morning and from the west in the evening. Temperature ranges normally from a low of near 10 degrees Fahrenheit in January to as high as 90 degrees in July.

## **Design Assumptions**

Critical design assumptions used in preparing this plan include a description and quantity of the industrial waste, general characterization of the waste, and the regulatory framework for disposal of industrial wastes. Please refer to the Reference Drawings in Appendix A for landfill design and site development details.

## **Waste Description and Quantities**

The different industrial wastes currently disposed of at the landfill include the following:

- Miscellaneous industrial wastes are produced including paper products, plastic drums, dirt, wood products, metal drums, lunchroom wastes, scrap metal, and drained filters. The estimated volume of these wastes is 1,600 cubic yards per year. Hazardous or PCB containing wastes are excluded from the landfill.
- Sludges are produced from the duct and chimney buildup, wash bay sump, ash water storage tanks, plant drains and manholes, auto shop sump, lime slaker and tank, and the domestic wastewater treatment plant. All sludges must be dewatered and must pass a paint filter test before being disposed of in the landfill.

Industrial wastes should be disposed of within the locations shown on Plan Sheets 1, 3 and 4. These materials should be processed to the smallest practical volume during placement in the landfill. After reducing the volume of the wastes, the materials should be covered with at least 6 inches of compacted fly or bottom ash and then a thin veneer of pyrites or bottom ash by the end of each day that trash is deposited in the landfill. The wastes should be shaped so that water does not pond on top of the wastes. Based on the existing volume identified for the industrial wastes of 1,600 cubic yards per year, the industrial waste landfill will provide disposal capacity until the year 2027.

Hazardous or PCB containing wastes are excluded from the industrial landfill. At least one percent (1%) of waste loads will be reviewed and characterized in detail and recorded on a log sheet. Inspection procedures will consist of the waste being spread out on the ground, and the perimeter of the waste walked to check for hazardous or PCB containing materials. Inspection details will be recorded on a log sheet. The log sheet instructs that hazardous wastes are not permitted in the landfill, and contains a list of prohibited materials. Any prohibited materials will be removed from the waste load, containerized, and reported to the Landfill Manager. The completed inspection forms are maintained as part of the operating record.

## **Regulatory Requirements**

Utah Administrative Code Regulation R315-304 applies to the Huntington Plant landfill operations. These regulations classify industrial landfills into two categories: Class IIIa and Class IIIb. The Huntington Plant industrial landfill meets the requirements for a Class IIIb classification. The landfill is not open to the public, it receives waste generated solely from

on site and it does not receive hazardous waste. Industrial waste has been received at the landfill prior to 1998; thus the landfill is an existing Class IIIb landfill. Existing Class IIIb landfills have no siting restrictions.

The regulatory requirements for operation, closure and post-closure care for Class IIIb Landfills are summarized:

1. Develop, keep on file, and abide by a plan of operation approved by the Utah Department of Environmental Quality (UDEQ) Executive Secretary. The plan of operation shall include the following:
  - A. Intended Schedule of Construction
  - B. Description of on-site solid waste handling procedures
  - C. Schedule for conducting inspections and monitoring the facility
  - D. Contingency plans in the event of a fire or explosion
  - E. Contingency plans for other releases such as failure of run-off containment system
  - F. Plan to control fugitive dust
  - G. Procedures for excluding the receipt of hazardous waste or waste containing PCBs
  - H. Closure and post-closure care plans
  - I. Cost estimates and financial assurance
  - J. General training and safety plan for site operators
2. Maintain and keep on-site or at a location approved by the UDEQ Executive Secretary the following:
  - A. Weights or volumes, number of vehicles entering and the types of wastes received each day
  - B. Deviations from the approved plan of operation
  - C. Training and notification procedures
  - D. Inspection log
  - E. Closure and post-closure care plans
  - F. Cost estimates and financial assurance documentation
3. Prepare an annual report and place the report in the facility's operating record. A copy of the report shall be submitted to the Executive Secretary by March 1<sup>st</sup> of each year. The annual report shall cover facility activities during the previous year and must include the following information:
  - A. Name and address of facility

- B. Calendar year covered by the report
  - C. Annual quantity in tons or cubic yards and estimated in-place density in pounds per cubic yard of solid waste handled
  - D. Annual update of the required financial assurance mechanism
  - E. Training programs or procedures completed
4. Inspect the landfill facility to prevent malfunctions and deterioration, operator errors, and discharges which may cause or lead to the release of wastes to the environment or to a threat to human health. These inspections must be conducted with sufficient frequency (no less than quarterly) to identify problems in time to correct them before they harm human health or the environment. The inspection log or summary shall include the following:
- A. Date and time of inspection
  - B. Printed name and handwritten signature of the inspector
  - C. Notation of observations made and the date and nature of any repairs or corrective action
  - D. Logs must be kept for a minimum of three years
5. Design the landfill to minimize the acceptance of liquids and control storm water run-on/run-off.
6. Provide for the following:
- A. Fencing at the property boundary or the use of other artificial or natural barriers to impede entry by the public and large animals. A lockable gate shall be required at the entry to the landfill.
  - B. Erecting a sign at the facility entrance that identifies at least the name of the facility, unacceptable materials, and an emergency telephone number.
  - C. Adequate fire protection to control any fires that may occur at the facility.
  - D. Preventing the potential harborage in active areas of rat and other vectors
  - E. Minimize the size of the unloading area and working face as much as possible
  - F. Approach and exit roads of all-weather construction, with traffic separation and traffic control on-site and at the site entrance
  - G. Communication, such as telephone or radio, between employees working at the landfill and management offices to handle emergencies.
7. Prevent the disposal of unauthorized waste by ensuring that at least one person is on site during hours of operation and shall prevent unauthorized disposal during off-hours by controlling entry.

8. Employ measures to prevent emissions of fugitive dusts, when weather conditions or climate indicate that transport of dust off-site is liable to create a nuisance.
9. Cover timber, wood, and other combustible waste with a minimum of six inches of soil, or equivalent, to avoid a fire hazard.
10. Plats and a statement of fact concerning the location of any disposal site shall be recorded as part of the record of title with the county recorder not later than 60 days after certification of closure. Proof of the record of title filing shall be submitted to the Executive Secretary.
11. Close the facility in a manner that will:
  - A. Minimize the need for maintenance
  - B. Minimize or eliminate threats to human health and the environment from escape of solid waste constituents, leachate, gases, or contaminated run-off to the groundwater, surface water, or the atmosphere
  - C. Prepare the facility for the post-closure period
12. Develop, keep on file and abide by a closure plan approved by the UDEQ Executive Secretary.
13. The closure plan shall project time intervals at which sequential partial closure, if applicable, is to be implemented and identify closure cost estimates and projected fund withdrawal intervals for the associated closure costs from the approved financial assurance instrument.
14. Landfills shall be closed by:
  - A. Leveling the waste
  - B. Covering the waste with a minimum of 2 feet of soil, including six inches of topsoil
  - C. Contouring the cover to minimum 2 percent surface slopes and maximum 33 percent side slopes, except where integrity and erosion control can be demonstrated at steeper slopes
15. Notify the UDEQ Executive Secretary of the intent to implement the closure plan in whole or part, 60 days prior to the project final receipt of waste at the unit or facility.
16. Commence implementation of the closure plan, in part or whole, within 30 days after final elevation is attained in part or all of the facility closure plan. Closure activities shall be completed within 180 days from their starting time.
17. Within 90 days following completion of closure, submit to the UDEQ Executive Secretary the following:
  - A. Facility or unit closure plan sheets signed by a professional engineer registered in the state of Utah, and modified as necessary to represent as-built changes to final closure construction as approved in the closure plan

- B. Certification by the owner or operator and a professional engineer registered in the state of Utah that the site or unit has been closed in accordance with the approved closure plan.
18. Provide post-closure activities for facility maintenance and monitoring of gases, land, and water for 30 years or as long as the UDEQ Executive Secretary determine is necessary for the facility to become stabilized and to protect human health and the environment.
  19. Develop, keep on file, and abide by a post-closure plan. The post-closure plan shall project time intervals at which post-closure activities are to be implemented and identify post-closure cost estimates and project fund withdrawal intervals from the selected financial assurance instrument.
  20. Commence post-closure activities after closure activities have been completed.
  21. Submit a certification to the UDEQ Executive Secretary when post-closure activities are complete, signed by the owner or operator and a professional engineer registered in the state of Utah stating why post-closure activities are no longer necessary.

## **Landfill Phasing**

The final closed landfill surface is shown in Plan Sheet 4. This configuration was based on the following constraints:

- Maximum elevation of 6,875 feet which matches the adjacent undisturbed land.
- Maximum side slopes of 3:1 (h:v).
- Placement of plant industrial wastes only starting in the Year 2003 and running to the Year 2027.
- Closure of the industrial waste landfill according to Utah DSHW regulations in the Year 2027.

Industrial wastes should be disposed of within the locations shown on Plan Sheets 1, 3, and 4, which will keep the industrial wastes in one location for the remaining life of the landfill. These materials should be processed to the smallest practical volume during placement in the landfill. Based on the existing volumes identified for the industrial wastes, a complete year of landfiling should produce a volume of industrial waste approximately 100 feet square and 5 feet high.

## **Industrial Wastes**

The industrial waste landfill site receives miscellaneous non-hazardous wastes generated on site, including some food scraps, paper products, empty metal, plastic and glass containers, dunnage, construction materials and other trash. The industrial waste sites will be operated in compliance with Utah Division of Solid and Hazardous Waste regulations. Non-commercial industrial solid waste disposal facility requirements are as follows: (Ref Utah R315-304-6)

- a. Materials disposed of in the landfill will be compacted to the smallest practical volume before final placement against the working face and covered.
- b. At the end of the operating day when material is disposed of in the landfill, after compacting and pushing the waste material against the working face, the material will be completely covered with at least 6 inches of earth, fly ash or other suitable cover material. This is part of the litter, rodent and insect control procedures.
- c. The working area will be developed so that water will not be allowed to pond above or in the operating area. The working face will be kept small for fugitive dust control.
- d. When the primary waste area has been filled to design capacity, the cell will be covered with 2 feet of compacted cover soil, including six inches of topsoil. It is possible that cells of ash could be placed above the industrial waste fill sometime in the future. For that reason, the final vertical and horizontal dimensions of the closed industrial waste area will be established by land survey and permanently recorded, along with dates the facility was opened and closed.
- e. Qualified personnel shall be at the facility to supervise activities during the operating days waste material is hauled to the facility to ensure the waste material is dumped in the designated location, compacted, and covered by the end of that operating day.
- f. Open burning shall not be permitted.
- g. Litter control along the access roads and at the facility shall be accomplished by clean-up of the areas as often as necessary to prevent unsightly conditions or windblown materials leaving the site.
- h. Provisions for dust control at the facility and along the access roads shall be implemented as necessary, normally in conjunction with similar controls associated with the ash landfill operations.
- i. Appropriate rodent and insect control procedures shall be implemented as necessary.
- j. Note that water treatment plant and digested wastewater treatment plant sludges containing no free liquid shall be placed on the working face and covered with other solid wastes or suitable cover material.
- k. Monthly inspections of the industrial waste site will be conducted to identify problems in time to correct them before they harm human health or the environment.
- l. The *Huntington Plant Emergency Procedures* shall be abided by in the event of a fire, explosion, and other releases such as explosive gases or runoff collection failure.
- m. A corrective action program shall be implemented if ground water is contaminated. Please refer to the *Monitoring* section of this document for details.
- n. Hazardous or PCB containing wastes are excluded from the landfill. Each load of waste material is reviewed and characterized by the truck driver and recorded on a log sheet. The driver is instructed and the log sheet reminds him that hazardous wastes are not permitted in the landfill.
- o. In the occurrence that the industrial landfill is inoperative, solid waste will be sent to the East Carbon Landfill or Emery County Landfill.

## **Slopes**

Final side slopes of the industrial landfill will be no steeper than 33%. It is suggested that temporary slopes be the same. The final top slope shall decline 2% toward the south, which is consistent with the surrounding ash landfill.

## **Alternative Plan for Waste Handling**

In the occurrence that the industrial landfill is inoperative, solid waste shall be sent to the East Carbon Landfill or the Emery County Landfill.

## **Monitoring**

Inspections will be conducted monthly to identify problems in time to correct them before they harm human health or the environment.

## **Corrective Action Plan for Contaminated Ground Water**

An investigation shall be initiated if contamination is detected in ground water. The investigation shall involve working in accordance with state agencies to determine the extent of the problem and the proper solution.

## **Contingency Plan**

The "*Huntington Plant Emergency Procedures*", shall be abided by in the event of a fire, explosion, and other releases such as explosive gases or run-off collection failure.

## **Landfill Closure**

This section covers the final cover system, seeding and fertilizing, storm water management, and access road maintenance.

## **Final Cover System**

The regulations for final cover systems for Class IIIb industrial landfills in Utah consist of 2 feet of soil cover including 6 inches of topsoil to support vegetative cover. This standard cover system only applies to the plant waste area that will be permitted as an industrial landfill. The recommended cover system for the industrial waste site is 18 inches of compacted borrow cover soil and 6 inches of topsoil, for a total of 24 inches. The current cover design specifies that the 24-inch soil cover will be purchased from an off-site source. The first 18-inches of cover will be compacted to a permeability of no less than  $1 \times 10^{-5}$  cm/sec. Hay mulch from the plant's research farm will be incorporated into the top 6-inches of soil to promote vegetation growth. For the remaining non-permitted areas of the landfill it is anticipated that 12 inches of cover soil be placed over the completed landfill. Should additional ash disposal cells be proposed over the top of the industrial cells, the final cover design may be revised.

The critical factor for a cover system is to minimize long-term erosion that minimizes the maintenance requirements for the cover system. As waste placement nears final grade, the surface should be graded in accordance with Plan Sheet 2 that shows the final cover system topography. The appropriate 18 inches of compacted borrow soil and 6 inches of topsoil should then be applied, fertilized and seeded to promote the growth of vegetation that will minimize erosion. The specific seeding and fertilizing recommendations are summarized in the following paragraphs.

### **Seeding and Fertilizing**

Once the final landfill slopes and elevations have been formed, a layer of bottom ash and pyrites should be placed to reduce the generation of dust and to provide a suitable surface for growing vegetation. Next, a soil cap should be placed over the bottom ash as the final root zone material. The recommended cover system for the industrial waste site is 18 inches of compacted borrow cover soil and 6 inches of topsoil, for a total of 24 inches.

The seeding procedure of the selected erosion control species will be dependent on the slope of the land and the selected method of seeding. On the flatter slopes (3:1 or flatter) seeding is best done with a Brillion-type grain seed drill followed by a ring roller. Prior to seeding on the flatter slopes a commercial fertilizer (500 pounds per acre of 15-15-15 or equivalent) should be broadcast over the entire area to be seeded. On steeper slopes (3:1 or steeper), hydroseeding is recommended. Fertilization can be done in the hydroseeding or by hand broadcasting. If the area is to be hydroseeded, then tracking with a tracked vehicle up and down the slope to create seeding pockets should be performed (track cleats create small pockets in the soil). Hydroseeding could consist of fertilization, seed mix, an appropriate mulch material at 1,500 dry pounds per acre, and a tackifier at manufacturer recommended coverage.

If temporary irrigation is available, then seeding can be done in September or early October. Otherwise seeding should be done in mid-October. An appropriate final reclamation seeding mix for Desert Salt Shrub, as defined by the Price, Utah BLM, is presented in Table 1.

Another option for grassing the landfill would be the recommendations of the Utah Department of Wildlife Resources. These recommendations were developed with the intent of producing browse for deer. The requirements from Wildlife Resources involve more stringent seeding requirements that are not required for erosion control. Unless the more stringent deer browse seeding requirements are necessary, it is recommended that the natural seed mix described in Table 1 be used for the final vegetative cover.

Table 1  
Recommended Vegetative Cover

Grasses and Forbs	Scientific Name	Pounds/acre
Indian ricegrass	Oryzopsis hymenoides	2
Squirreltail	Elymus elymoides	2
Galleta	Hilaria jamesii	2
Lewis flax	Linum perenne lewisii	1
Palmer penstemon	Penstemon palmerii	1
Gooseberryleaf globemallow	Sphaeralcea grossulariifolia	0.5
<b>Shrubs</b>		
Forage kochia	Kochia prostrata	2
Rubber rabbitbrush	Chrysothamnus nauseosus	1
Fourwing saltbush	Atriplex canescens	2
Winterfat	Krasheninmkovia (Eurotia) lanata	2
<b>TOTAL</b>		<b>15.5</b>

## Storm Water Management

A detailed description of the storm water management system at the landfill is included in the plant-wide Storm Water Pollution Prevention Plan. The following discussion presents a brief description of the required components for storm water management for the landfill area.

Operation of the industrial landfill will be conducted in a manner that will minimize the amount of storm water run-on and runoff that contacts the waste. As waste is placed in the landfill, application of daily cover will minimize the amount of water contacting the waste. The working area will be sloped to promote drainage away from the waste, and berms will be installed to prevent run on water from contacting the waste, and also to prevent any water that has contacted the waste from leaving the active landfill area. The area surrounding the industrial landfill will be graded such that precipitation is transmitted away from the active landfill area, and then to the detention ponds at the toe of the slope. To promote runoff, as opposed to infiltration of rainfall into the wastes, the waste surface should be sloped at a minimum of 2 percent to the edges of the landfill. Any run-on from offsite areas should be collected in swales at the landfill boundary.

## Post-Closure Plan

PacifiCorp will provide care for the landfill facility following the date of final completion of closure in a manner that assures the facility and facility structures are maintained and operated as intended.

## Post-Closure Care Activities

PacifiCorp will maintain the approved final contours and drainage system of the site to minimize precipitation run-on, minimize erosion, optimize drainage of precipitation, and provide a surface drainage system which in no way adversely affects proper drainage from adjacent lands. The facility will be inspected quarterly for evidence of run-on, erosion of the final cover, and ponding of water on the final cover. Appropriate actions to correct these conditions will be undertaken and may include construction of drainage ditches or diversion dikes to prevent run-on, repair of erosion damage, as well as repair and grading of areas of ponding water on the final cover.

PacifiCorp will assure that a healthy vegetative cover is established and maintained over the site. The facility will be inspected quarterly for areas of poor vegetative cover. Such areas will be prepared and reseeded in order to establish adequate vegetative cover. Annual fertilization of the facility will be undertaken at least until the vegetative cover is established sufficiently to render such maintenance unnecessary.

Drainage ditches, berms, and the storm water retention ponds will be maintained until the vegetative cover is established sufficiently to render such maintenance unnecessary. Drainage ditches and berms will be inspected quarterly for evidence of damage or restricted flow caused by erosion or sedimentation. Such blockages will be removed expeditiously.

## Dust Management

Detailed descriptions of the methods to be implemented for controlling dust are included in the Huntington Plant Title V Air Permit and should be referred to as necessary.

## Operational Documentation

Monitoring the effectiveness of this operations plan should be performed as part of the control monitoring testing. As part of the annual reporting process required by the Utah DSHW, PacifiCorp's Landfill Manager will evaluate the effectiveness of the Plan and make any procedural or plan changes as necessary. This section also includes additional measures that will be completed to ensure that the *Landfill Operations Plan* meets its original objectives.

The Huntington Plant's designated Landfill Manager and individual to whom the waste hauling and site maintenance contractor is responsible to is:

Darce Guymon  
Huntington Plant  
Highway 31 W. of Huntington City  
Huntington, Utah  
(435) 687-4305

The Huntington Plant may change the Landfill Manager periodically as needed. The Landfill Manager shall be designated by the Huntington Plant management. All revisions to

the *Landfill Operations Plan* shall be done by the Landfill Manager and approved by the Huntington Plant management.

### **Facility Inspections**

Facility inspections can be conducted at the discretion of the Landfill Manager. The industrial waste areas shall be inspected to ensure that the requirements of Utah Administrative Code Section R315-304 are being satisfied.

### **Training**

The Huntington Plant through the Landfill Manager shall conduct ash pile and industrial waste training seminars to involved PacifiCorp employees and Contractor's personnel. Generally, training seminars will be conducted when operating personnel changes are made by PacifiCorp or the Contractor. Also, training seminars are to be conducted when major changes in the *Landfill Operations Plan* occur. This training should be performed as needed to assist the employees in executing and fulfilling their responsibilities. Training records will be kept identifying who was trained, the training subject, and the date trained.

**Appendix E.**  
**Huntington Power Plant Emergency Procedures**

# Huntington Plant Administrative Instructions

HTG-SAF-002

Revised: 2-28-06

Title: **Plant Emergency Procedures**

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**Definitions**

**Incident Commander – Shift Supervisor**

**Communication Coordinators – Control Room Operators**

**Hazmat Team – Lab Techs**

**Fire Team – Plant Operators**

**Medical Team – HERT Team Members**

**Whenever the emergency alarm is sounded for a code red, yellow or blue, all employees and contractors will return to their various shops/offices for a head count and to receive further instructions from their supervisors. Any discrepancies shall be reported to Security. Security shall report total discrepancies to the Shift Supervisor after all shops have reported. Supervisors shall report to the Shift Supervisor if Security is not available.**

The plant policy for dealing with blood borne pathogens can be found on the PacifiCorp Electronic Document Management System (EDMS) available at the Huntington Plant. PAI-SS-25, Bloodborne Pathogens, should be consulted when dealing with Code Blue or other emergencies where blood borne pathogens may be involved.

It is the responsibility of each employee to become familiar with the locations of the telephones, fire extinguishers, first aid kits, emergency exits and evacuation routes.

## **I. HAZARDOUS CHEMICAL RELEASE (MAJOR RELEASE)**

### **CODE YELLOW**

Operators and Lab Techs are primary responders. HERT Team Members will report to their supervisors, then to the Mechanic Shop. One team member will call the Control Room Operator, who will call the Shift Supervisor (Incident Commander). The Incident Commander will determine if the HERT Team is needed and will have the CRO either direct the Team to the staging area or have them remain in the Mechanic Shop until further notice. All other employees and contractors shall report to their various shops/offices unless otherwise directed.

MSDS sheets are available from 3E Company on the company Intranet or by dialing 6737 (MSDS). Security also has MSDS sheets available and the Huntington Plant Emergency Chemical Spill Plan has MSDS sheets for bulk commodities at the plant.

### **INITIATOR'S RESPONSIBILITY (PERSON IDENTIFYING RELEASE):**

- 1.0 Protect yourself and others from injury then call 4911 and quickly explain:
  - 1.1 Who you are (name).
  - 1.2 Location of the incident.
  - 1.3 Type of hazardous material involved
  - 1.4 Is the incident dangerous to personnel?
  - 1.5 Do not hang up until the CRO instructs you to do so.
  - 1.6 Proceed to a safe location and keep others away.

### **CONTROL ROOM OPERATOR (CRO) RESPONSIBILITY (COMMUNICATION COORDINATOR):**

- 1.0 When the emergency phone rings, the CRO will answer it immediately.
- 2.0 Complete an "OPERATIONS EMERGENCY PAGING PROCEDURE - CODE YELLOW". Repeat the information back to the caller.
- 3.0 Notify the Shift Supervisor (Incident Commander) and a Lab Tech to determine the level of response.
- 4.0 If the Shift Supervisor requests help from the entire Hazmat Team or wishes to notify the entire plant of the incident the CRO shall:
  - 4.1 Access the plant P.A. System (795).

**Plant Emergency Procedures**

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- 4.2 Announce "We have a code yellow-a chemical release, we have a code yellow-a chemical release, we have a code yellow located at \_\_\_\_\_, we have a code yellow located at \_\_\_\_\_.
- 4.3 Hang up and sound the emergency alarm for five (5) seconds.
- 4.4 Repeat steps 4.1 through 4.3 once more and then again every ten (10) minutes until the Incident Commander is satisfied that all employees on site are safe and aware of the incident.
- 5.0 Activate the HERT team and/or FIRE team if requested by the Shift Supervisor.
- 6.0 Call for any outside assistance needed and notify the Outside Plant Operator to report to Security for escort, if requested by the Shift Supervisor.
- 7.0 Notify the following people:
  - 7.1 Plant Superintendent
  - 7.2 Plant Chemist
  - 7.3 Safety Administrator
  - 7.4 Environmental Engineer
  - 7.4.1 Reporting to outside agencies shall be done through the Environmental or Legal Departments of the Company. Call **503-813-6797** to contact a Company representative.
- 8.0 Initiate evacuation procedures if requested by the Shift Supervisor. (see evacuation procedures)

**SHIFT SUPERVISOR RESPONSIBILITY (INCIDENT COMMANDER):**

- 1.0 Team up with a Lab Tech to determine the level of response needed.
- 2.0 Notify CRO if entire Hazmat Team response is needed.
- 3.0 Meet with the Hazmat Team in the Lab to determine and plan a safe response.
  - 3.1 Call out more Lab Techs if conditions require.
- 4.0 If the situation is such that control and containment is not safely possible using level B turnout gear only, implement appropriate evacuation distances.
- 5.0 If situation can be contained, proceed with containment and set up appropriate barricades.

**LAB TECHNICIAN'S RESPONSIBILITY (HAZMAT TEAM):**

- 1.0 The Lab Tech. helping the Shift Supervisor to determine the level of response becomes the Safety Officer and has authority to stop any or all response procedures.
- 2.0 When the code yellow alarm is initiated, proceed immediately to Lab or designated location (as directed by the Shift Supervisor).
- 3.0 Response gear is available in the Hazmat trailer.
- 4.0 The Shift Supervisor will direct you on the course of action to be taken and is your supervisor (lab and water treatment responsibilities are suspended).
- 5.0 The "Buddy System" will be used as needed.

**ALL OTHER PERSONNEL:**

- 1.0 Report to your immediate supervisor for instructions or as directed by the P.A. System.
- 2.0 Do not use the plant phone system or the P.A. System until the emergency is cleared.

**Note:** Minor releases are to be handled by the individual worker for the substances that they work with. The individual worker will be trained for such minor releases as to the proper containment, clean up, and reporting necessary. If the worker is unsure of the response necessary, he/she is to implement the above response as the initiator.

**SCBA Locations**

Coal Yard Locker Room  
Scrubber Control Room  
Lab  
Control Room

Transfer Tower Load Center  
Unit 1 DC Room  
Combined Response Trailer

**Decontamination Procedures:**

Personnel and equipment exiting a level B response zone shall be thoroughly decontaminated. The standard decontamination protocol shall be used with the following stations:

1. Segregated equipment drop
2. Outer garment, boots and gloves wash and rinse

3. Outer garment, boots and glove removal
4. SCBA removal
5. Field wash

After a Code Yellow, a review will take place with those involved and the Safety Department.

## **II. FIRE**

### **CODE RED**

Operators are primary responders. HERT Team Members will report to the Mechanic Shop after reporting to their supervisors. One team member will call the Control Room Operator, who will call the Shift Supervisor (Incident Commander). The Incident Commander will determine if the HERT Team is needed and will have the Control Room Operator either direct the HERT Team to the staging area or have the Team remain in the Mechanic Shop until further notice.

#### **INITIATOR'S RESPONSIBILITY (PERSON WHO FINDS FIRE):**

- 1.0 Locate the nearest plant phone and dial 4911 and quickly explain:
  - 1.1 Who you are (name).
  - 1.2 How extensive or serious the fire is.
  - 1.3 The location of the fire.
  - 1.4 Type of material on fire.
  - 1.5 Ask the CRO to repeat the above information back to you.
  - 1.6 Return to the scene if safety permits and proper response equipment is available and begin fire fighting.
  - 1.7 If additional fire fighting equipment is needed, do not attempt a response that will endanger you or others. Wait for help and keep others away from danger.
  - 1.8 Remain on the scene to help the Fire Fighting Team.

#### **CONTROL ROOM OPERATOR (CRO) RESPONSIBILITY (COMMUNICATION COORDINATOR):**

- 1.0 When the emergency phone rings, the CRO will answer it immediately.
- 2.0 Complete an "OPERATIONS EMERGENCY PAGING PROCEDURE – CODE RED". Repeat the information back to the caller.
- 3.0 Use the plant paging system to alert plant personnel of the incident by following these steps:

**Plant Emergency Procedures**

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- 3.1 Access the plant P.A. System (795).
- 3.2 Announce "We have a code red-a fire, we have a code red-a fire. We have a code red located at \_\_\_\_\_. We have a code red located at \_\_\_\_\_."
- 3.3 Hang up and sound the emergency alarm for five (5) seconds.
- 3.4 Repeat steps 3.1 through 3.3 once more and again every ten (10) minutes until clear.
- 4.0 If requested by the Shift Supervisor, call 911 and request local fire department assistance.
- 4.1 Notify the Outside Plant Operator to report to Security for escort if outside assistance is requested.
- 5.0 Arrange for any additional fire fighting personnel, equipment, SCBA, etc. as requested by the Shift Supervisor.
- 6.0 Notify the following people of any **major** fire emergency:
  - 6.1 Plant Manager
  - 6.2 Operations Superintendent
  - 6.3 Maintenance Superintendent
  - 6.4 Safety Administrator
  - 6.5 Dispatcher

**Note:** A minor fire can be extinguished by one person using a fire extinguisher. Anything else is considered a major fire.

**SHIFT SUPERVISOR RESPONSIBILITY (INCIDENT COMMANDER):**

- 1.0 Report to the scene and maintain radio contact with the control room.
- 2.0 Delegate responsibilities and coordinate the activities of the fire fighting team.
- 3.0 Isolate electrical equipment that may otherwise cause hazard to the fire fighting team.
- 4.0 Determine if outside fire fighting response is needed.
- 5.0 Utilize the CRO as necessary to facilitate prompt handling of additional needs or requests.

**PLANT OPERATORS:**

- 1.0 Proceed to the scene picking up fire extinguishers on the way and assist in fire fighting efforts as directed by the Incident Commander.

**Plant Emergency Procedures**

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**2.0 Outside Plant Operator**

- 2.1 Proceed to the diesel fire pump location and observe pump valving, fuel supply and pump operation.
- 2.2 If directed, proceed to Security to escort off site assistance.

**3.0 The "Buddy System" will be used as needed.**

**ALL OTHER PERSONNEL:**

- 1.0 All other plant personnel, other than those previously listed, will report to their supervisor's office location
- 2.0 Contract or Non-Plant personnel should proceed to the employee parking lot.
- 3.0 Do not use the phone system or P.A. System until the fire emergency is concluded.

**III. MEDICAL EMERGENCY  
(MAJOR INJURY)**

**CODE BLUE**

HERT Team Members and Operators are primary responders. HERT Team Members shall be in command of all Code Blue Emergencies under the direction of the Incident Commander. Plant Operators shall report to the scene of a Code Blue with jump kits and begin first aid until relieved by HERT Team Members. If no HERT Team Members are present, Plant Operators shall handle the response.

HERT Team and Plant Operators shall direct all aspects of a medical emergency and shall help determine the need for outside medical assistance. The Control Room shall call for outside assistance.

**INITIATOR'S RESPONSIBILITY (FIRST PERSON ON THE SCENE):**

- 1.0 Protect yourself and others from injury then call 4911 and quickly explain:
  - 1.1 Location of victim(s)
  - 1.2 Number of victims
  - 1.3 Type of injury or illness
  - 1.4 Is patient breathing
  - 1.5 Is patient conscious
  - 1.6 Does he/she have a head injury
  - 1.7 Is there severe bleeding
  - 1.8 Ask the CRO to repeat the information back to you

**Plant Emergency Procedures**

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- 1.9 Do not hang up until the CRO instructs you to do so

**CONTROL ROOM OPERATOR (CRO) RESPONSIBILITY  
(COMMUNICATION COORDINATOR):**

- 1.0 When the emergency phone rings, the CRO will answer it immediately.
- 2.0 Complete an "OPERATIONS EMERGENCY PAGING PROCEDURE – CODE BLUE". Repeat the information back to the caller.
- 3.0 Use the plant paging system to alert plant personnel of the incident by following these steps:
  - 3.1 Access the P.A. System (795).
  - 3.2 Announce "We have a code blue-a medical emergency. We have a code blue-a medical emergency. We have a code blue located at \_\_\_\_\_. We have a code blue located at \_\_\_\_\_".
  - 3.3 Hang up and sound the emergency alarm for five (5) seconds.
  - 3.4 Repeat steps 3.1 through 3.3 once more.
- 4.0 If requested by the Shift Supervisor or HERT Team member the CRO shall call 911 and request assistance from the Emery County EMT Dispatcher.
  - 4.1 The CRO shall notify the Outside Plant Operator to report to Security for escort.
- 5.0 Notify the following people:
  - 5.1 Plant Manager
  - 5.2 Operations superintendent
  - 5.3 Maintenance superintendent
  - 5.4 Safety administrator
  - 5.5 Dispatch (If possible LTA, electrical contact, or death)

**SHIFT SUPERVISOR RESPONSIBILITY (INCIDENT COMMANDER):**

- 1.0 Respond to the scene and maintain radio contact with the control room.
- 2.0 Help determine if outside emergency response is necessary.
- 3.0 Delegate responsibilities and coordinate the activities of the Emergency Response Team.
- 4.0 Use CRO as necessary to facilitate prompt handling of additional needs or requests.
- 5.0 Keep crowd control. Injured persons do not like large crowds.

**Plant Emergency Procedures**

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**HERT TEAM MEMBERS:**

- 1.0 Report to the scene with jump kits and other first aid equipment.
- 2.0 Communicate with the Shift Supervisor and help determine if outside assistance is needed.
- 3.0 At the conclusion of a Code Blue, a review will take place with those involved.

**ALL OTHER PERSONNEL:**

- 1.0 Report to your immediate supervisor for a head count and further instructions. Do not go to the scene unless your services are needed. Bystanders do not help the victim and may hamper the response efforts.

**JUMP KIT LOCATIONS**

RCC Control Room	Administration Building by mail boxes
I & C Shop	Electric Shop
Warehouse Lunch Room	Scrubber
Lab	Control Room
Coal yard Office	Combined Response Trailer

**Transport of Victims and Notification of Next of Kin.**

All victims of injury/illness who require emergency transport to an off site medical facility shall be transported by a professional ambulance service with appropriate resources.

When an employee is transported the Incident Commander shall notify the highest supervisory person available at the plant. This person shall then contact the injured employee's next of kin. The next of kin shall be informed of the following:

- The employee's name and the nature of the injury/illness.
- The medical facility to which the employee is being transported.
- The time the ambulance left the plant site.

All victims whose injuries or cause of symptoms are unknown, i.e. chest pains, dizziness, etc. shall be transported by ambulance.

Employees with minor injuries or requiring non-emergency treatment may be transported by company vehicle if approved by the Incident Commander.

## **IV. EARTHQUAKE**

### **DURING THE EARTHQUAKE:**

- 1.0 Take cover underneath a desk or table. Protect your head and neck.
- 2.0 Stay away from windows or objects that could fall on you.
- 3.0 Stay where you are, **DO NOT** run outside. Falling debris may cause injury.
- 4.0 **DO NOT** use elevators.
- 5.0 If outdoors, stay in an open area. **DO NOT** enter the building.

### **AFTER THE EARTHQUAKE:**

- 6.0 Remain calm and prepare for aftershocks.
- 7.0 Act on any emergency situation created by the earthquake.

## **V. EVACUATION**

### **SHIFT SUPERVISOR RESPONSIBILITY (INCIDENT COMMANDER):**

- 1.0 The Shift Supervisor will determine if an evacuation is necessary.
- 2.0 Radio or phone contact will be made to the Control Room Operator instructing him/her of the situation and requesting an evacuation.
- 3.0 Security will report any missing employees (PacifiCorp or contract) to the Shift Supervisor.

### **CONTROL ROOM OPERATOR (CRO) RESPONSIBILITY (COMMUNICATION COORDINATOR):**

- 1.0 Upon receiving notification from the Shift Supervisor of the need to evacuate, the CRO will:
  - 1.1 Sound the emergency alarm for five (5) seconds.
  - 1.2 Access the plant P.A. System (795).
  - 1.3 Announce "We have an evacuation alert. We have an evacuation alert. All personnel report to the parking lot. All personnel report to the parking lot. Stay clear of the \_\_\_\_\_ area. Stay clear of the \_\_\_\_\_ area".
  - 1.4 Repeat steps 1.1 through 1.3 once more.

**Plant Emergency Procedures**

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- 1.5 If there is a possible threat to the local community or if assistance is needed, call 911 and inform the local emergency dispatcher of the situation.
- 2.0 Notify the following by phone:
  - 2.1 Coal Yard (4370)
  - 2.2 Communications (4114)
  - 2.3 TPM (4359)
- 3.0 Notify the following by radio:
  - 3.1 Ashworth (channel 25)
  - 3.2 Coal Receiving (channel 27)

**ALL SUPERVISORS ON SITE:**

- 1.0 When instructed to do so over the P.A., report to the parking lot and begin a head count of your crew. Report any missing crewmembers to Security.
- 2.0 Plant representatives are responsible for their contractor crew counting.

**VI. BOMB THREAT**

**INITIATOR (PERSON RECEIVING THREAT):**

- 1.0 Bomb threats should be taken seriously. Do not assume that bomb threats are made only to management or security personnel. Anyone can receive a bomb threat and everyone should be prepared.
- 2.0 In the event a bomb threat is received by telephone:
  - 2.1 Remain calm. Use the bomb threat checklist.
  - 2.2 Do not hang up until the other person does.
  - 2.3 Do not use a radio.
  - 2.4 Call the CRO by phone (4911).
  - 2.5 Provide requested information.
  - 2.6 Do not hang up until the CRO does.
- 3.0 If suspicious object is found:
  - 3.1 Do not touch the object.
  - 3.2 Do not use the radio.
  - 3.3 Call the CRO by phone (4911).
  - 3.4 Provide requested information.

**Plant Emergency Procedures**

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- 3.5 Do not hang up until the CRO does.

**CONTROL ROOM OPERATOR (CRO) RESPONSIBILITY  
(COMMUNICATION COORDINATOR):**

- 1.0 If an emergency call is received, inform the Shift Supervisor
- 2.0 DO NOT USE THE RADIO.
- 3.0 Contact the following:
  - 3.1 Plant Manager
  - 3.2 Operation Superintendent
  - 3.3 Maintenance Superintendent
  - 3.4 Safety Administrator
- 4.0 Remain in the control room until told to leave or conditions warrant leaving.

**SHIFT SUPERVISOR RESPONSIBILITY (INCIDENT COMMANDER):**

- 1.0 Should evacuation become necessary, follow the steps outlined in the Evacuation Section of this manual.
- 2.0 Contact the Emery County Sheriff's Office to report the threat.
- 3.0 Let law enforcement officials handle any locating or transporting of a bomb.
- 4.0 If safe, send plant personnel back to their work areas.
- 5.0 Notify System Dispatch of the incident.

**GENERAL EMPLOYEE, CONTRACTOR AND VISITOR:**

- 1.0 If an evacuation is announced over the P.A. system, report immediately to the employee parking lot.
- 2.0 Wait for further instructions from your supervisor or the Shift Supervisor.
- 3.0 Do not use phones, radios, or the P.A. system until the emergency is cleared.

**Plant Emergency Procedures**

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Most bomb threats are made by telephone. If you receive a bomb threat by telephone, you should attempt to obtain as much information from the caller as possible. This will assist Emergency Response Teams in determining the course of action to be taken and will assist the Sheriffs Department with their investigation.

1. Remain calm.
2. Ask the caller the following questions:
  - When will the bomb go off? \_\_\_\_\_
  - Where is the bomb located?  
\_\_\_\_\_  
\_\_\_\_\_
  - What does it look like?  
\_\_\_\_\_  
\_\_\_\_\_
  - Is it in a container? What type?  
\_\_\_\_\_  
\_\_\_\_\_
  - What type of device is it?  
\_\_\_\_\_  
\_\_\_\_\_
  - What is your name?  
\_\_\_\_\_
  - How do you know about this?  
\_\_\_\_\_  
\_\_\_\_\_
  - Why was the bomb placed?  
\_\_\_\_\_  
\_\_\_\_\_

**Plant Emergency Procedures**

3. Record the following information:

- Exact time of the call

\_\_\_\_\_

- Caller's exact words

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

- Any background noises

\_\_\_\_\_

\_\_\_\_\_

- Any accent or voice characteristics that may help identify the caller

\_\_\_\_\_

\_\_\_\_\_

MALE

FEMALE

YOUNG

OLD

CALM

NERVOUS

LOUD

SOFT

Other characteristics

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

## **VII. POWER OUTAGES**

### **ALL PLANT PERSONNEL:**

#### LOCALIZED POWER OUTAGE

In the event of a power failure in your work area:

- 1.0     Remain calm.
- 2.0     If it is safe, move to an area that is lighted. If it is unsafe, stay where you are and wait for light to be restored or help to arrive.
- 3.0     If the power failure appears to be localized to your area, notify the CRO, extension 4251 or 4252.
- 4.0     If there is a need for emergency help, call the CRO:

By Phone:     Extension 4911

#### TOTAL BUILDING POWER OUTAGE

- 1.0     Remain calm
- 2.0     DO NOT move about your area – wait until emergency power and lighting is restored or help arrives.
- 3.0     Follow instructions from announcements made over the public address system and radios.

# Operations Emergency Paging Procedure

## **CHEMICAL RELEASE**

### **CODE YELLOW**

Name of person reporting incident \_\_\_\_\_

Location of incident \_\_\_\_\_

Name of chemical released (if known) \_\_\_\_\_

Is the incident dangerous to other personnel?      YES      NO

Repeat this information back to the person reporting the incident.

Inform the initiator to remain clear and help keep others away until the Hazmat Team arrives.

# Operations Emergency Paging Procedure

## **FIRE**

### **CODE RED**

Name of person reporting incident \_\_\_\_\_

Location of incident \_\_\_\_\_

How extensive or serious is the fire? \_\_\_\_\_

What type of material is on fire? \_\_\_\_\_

Repeat this information back to the person reporting the incident.

Inform the initiator to remain clear until help arrives.

# Operations Emergency Paging Procedure

## **MEDICAL EMERGENCY**

### **CODE BLUE**

Name of person reporting incident \_\_\_\_\_

Location of incident \_\_\_\_\_

Number of victims \_\_\_\_\_

Type of injury or illness \_\_\_\_\_

Is the patient breathing and conscious?                      YES                      NO

Does he/she have a head injury?                      YES                      NO

Is there severe bleeding?                      YES                      NO

Repeat this information back to the person reporting the incident.

Inform the initiator to assist only if he/she is trained and protected from Bloodborne Pathogens.

**Appendix F.**  
**Closure/Post Closure Cost Spreadsheets**

**Attachment #1. Additional Information & Assumptions**  
**Huntington Power Plant**  
**Industrial Landfill Closure and Post-Closure Cost Estimates**

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**Closure Cost Spreadsheet**

Section 1.0: Engineering Costs

- 1.1) *Topographic Survey:* Assume third-party two-man survey crew for one day including travel, plus map development costs = \$1,500.
- 1.2) *Boundary Survey for Closure:* Assume third-party two-man survey crew for one-half day including travel, plus map development costs = \$1,000.
- 1.3) *Site Evaluation:* Estimate a Professional Engineer at \$90/hr x 16 hours = \$1,440, plus lump travel costs of \$300 = \$1,740.
- 1.4) *Development of Plans:* Estimate Staff Engineer at \$70/hr x 75 hours = \$5,250, and Professional Engineer at \$90/hr x 25 hours = \$2,250.
- 1.5) *Contract Administration:* Estimate Project Engineer at \$75/hr x 25 hours = \$1,875, plus PacifiCorp administrative overhead at \$50/hr x 25 hours = \$1,250.
- 1.6) *Administrative Closure Certification:* Estimate PacifiCorp administrative overhead at \$50/hr x 30 hours = \$1,500.
- 1.7) *Project Management, Construction Oversight:* Estimate Staff Engineer for construction oversight at \$70/hr x 120 hours = \$8,400, materials testing crew at \$1500/day x 3 days, and Professional Engineer at \$90/hr x 40 hours = \$3,600.
- 1.9) *Other Environmental Permit Costs:* Estimate Staff Engineer at \$70/hr x 40 hours = \$2,800 to obtain construction permits.

Section 2: Construction Costs

*General Construction Assumptions:*

- The 18-inch infiltration layer will be composed of fill material purchased from an off-site source, and will be compacted to a permeability of no greater than  $1 \times 10^{-5}$  cm/sec.
- The 6-inch erosion/vegetation layer will be taken from an existing on-site topsoil source, approximately ½ mile from the landfill.
- Costs in Section 2.4.1 include seeding, fertilizer, and mulch, based on previous similar construction projects.
- Construction crews proposed for closure activities are detailed in Attachment #2.
- Class IIb landfills are exempt from many closure requirements, including liners, drainage layers, leachate collection, and ground water monitoring (UAC R351-301 through 320).
- Excavation equipment and earthwork figures were developed using the *Caterpillar Performance Handbook* and the *RS Means Site Work and Landscape Cost Data*.

- Adjustments for operating efficiencies, overhead, profit, and incidentals have been built into costs except where noted.
- A 15% contingency was added to the total construction cost to cover contractor performance bond, insurance, taxes, and other incidental costs.

## 2.2 *Completion of Top Cover (Infiltration Layer-18")*

2.2.1a) *Soil Placement (Spread and Compact)*: Assume cover soil will be stockpiled around perimeter of landfill upon delivery. Estimate spreading of fill by a 300 H.P dozer and a 300-foot haul distance (Crew B10M-Attachment #2). The unit cost is \$2.73/CY x 8,681 CY = \$23,700. Capacity of one dozer crew is 600 CY/day. Using three dozers, the time to spread soil would be  $8681 \text{ CY} \div 1800 \text{ CY/day} = 4.82 \text{ Days}$ .

Soil compaction will be performed by a vibrating drum roller in 6-inch lifts with 4 passes per lift (Crew B10-Y – Attachment #2). Cost for this crew is estimated at \$0.48/CY x 8681 CY = \$4,167. The output of one roller crew under these conditions is 1900 CY/day, and there are 2,170 CY per 6-inch lift. The time to compact the soil would be 4.6 days, with compact work scheduled to start one day after soil spreading begins. As a result, the total time to spread and compact 18-inch infiltration layer is approximately 5.6 days.

2.2.1b) *Soil Processing*: Cover soil purchased from an outside source will not require any processing.

2.2.1c) *Soil Amendment*: Cover soil purchased from an outside source will not require any amendment.

2.2.1d) *Soil Purchase*: Based on the area of the completed solid waste landfill, the total compacted soil volume of the landfill cap is 9,260 bank CY. Assume a conservative swell factor of 25%, so  $9,260 \text{ bank CY} \times 1.25 = 11,575 \text{ loose CY}$ . The 18-inch infiltration layer =  $11,575 \times 0.75 = 8,681 \text{ CY}$ . Royalty costs for purchase and delivery of cover soil from an off-site source is \$3.50/CY.

2.2.1e) *Transportation*: Royalty costs listed in 2.2.1d include transportation costs.

2.3 *Erosion Layer Placement (Load, Haul, Spread, & Compact Soil - 6")*: The volume of soil for the 6-inch erosion layer is  $11,575 \text{ CY} \times 0.25 = 2,894 \text{ CY}$ .

Loading: Assume a wheel loader with a 5 CY bucket capacity to load topsoil into trucks. Estimate \$117/hr (Crew B10U-Attachmetn #2) for machine and operator. The average cycle time for normal loading conditions is 0.45 to 0.55 minutes, increase 15% for loading into trucks. Loader cycle time =  $0.50 \text{ min} \times 1.15 = 0.6 \text{ minutes}$ . Estimate 4 minutes to load a 12-CY truck, including truck staging allowance. Production is estimated at  $12\text{-CY per truck} \times 1 \text{ truck}/4 \text{ minutes} \times 50 \text{ minutes/hour efficiency} = 150 \text{ CY/hour}$ . The unit loader cost is \$117/hour x

1hr/150 CY = \$0.78/CY. Total loading cost = \$0.78/CY x 2894 CY = \$2,257. The total loading time would be 2894 CY ÷ 1200 CY/day = 2.4 days.

Hauling: Topsoil stockpile is estimated to be a roundtrip haul distance of 1 mile from the industrial waste landfill. Assume an average speed of 15 mph plus 6 minutes to load and unload = (1 mile/trip ÷ 15 mph) x 60 min/hr + 6 minutes = 10 minutes/trip. Estimate \$103/hr for operator and truck (Crew B34B-Attachment #2), and 12 CY/truck. The hourly truck production is 1 trip/10 minutes x 50 minutes/hr efficiency x 12 CY/truck = 60 CY/truck/hr x 8 hours = 480 CY/truck/day. The unit cost hauling time is \$103/hr x 1 hr/60 CY = \$1.72/CY. Total hauling cost would be \$1.72/CY x 2894 CY = \$4,978.

Spread: Use figures developed in Section 2.2.1a for spreading of the topsoil erosion layer. Assuming a unit cost of \$2.73/CY and 1800 CY/day capacity (three dozer crew), the cost to spread is \$2.73/CY x 2894 CY = \$7,900 and the time to spread is 2894 CY ÷ 1800 CY/day = 1.6 days.

- 2.4.1 *Seeding (Includes seed, mulch and fertilizer):* Based on various revegetation estimates developed from similar projects, a cost of \$2,500/acre will be used for revegetation work, which includes seeding, mulching and fertilizing. The total cost to revegetate the landfill will be \$2,500/acre x 2.85 acres (surface area of landfill) = \$7,125. The production of the revegetation crew (Crew B81-Attachment #2) is estimated at approximately 1 acre/day. The time to complete vegetative work at the site would be 3 days.
- 2.5 *Site Grading & Drainage:* Assume that no additional grading work will be necessary to control drainage around landfill.
- 2.6 *Site Fencing & Security:* Access to the industrial landfill is already controlled through a large berm around the landfill area, with a locking gate on the access road. As a result, no fencing costs have been included.

### Section 3: Gas Collection Costs

- The Huntington Industrial Landfill is exempt from gas collection requirements.

### Section 4: Monitoring Well Installation Costs

- The Huntington Industrial Landfill is exempt from ground water monitoring requirements.

## Post-Closure Cost Spreadsheet

### *General Post-Closure Assumptions:*

- The post-closure care period has been estimated at 30 years.
- For erosion layer repair (Section 2.1.1), replacement of one foot of cover over 5% of the landfill area per year was used.
- For vegetation repair (Section 2.1.2), replacement of 10% of the landfill area per year was used.

### Section 1: Engineering Costs

- 1.1) *Post-Closure Plan:* Estimate Staff Engineer at \$70/hr x 50 hours = \$3,500 and a Professional Engineer at \$90/hr x 25 hours = \$2,250.
- 1.2) *Site Inspection & Recordkeeping:* Estimate a Professional Engineer at \$90/hr x 12 hours = \$1,080, plus lump travel costs of \$300 = \$1,380.
- 1.3) *Correctional Plans:* Estimate Staff Engineer at \$70/hr x 20 hours = \$1,400.
- 1.4) *Site Monitoring:* The Huntington Landfill is exempt from ground water monitoring and gas collection requirements.

### Section 2: Maintenance Costs

#### *2.1) Cover Maintenance Costs*

- 2.1.1) *Soil Replacement:* The total area of the landfill is 125,000 SF x 0.05 = 6,250 SF x 1 ft cover = 6,250 CF x 1 CY/27 CY = 231 CY. Using the unit cost (developed in Section 2.3 of Closure Costs) to load, haul, and spread replacement soil, the annual soil replacement cost is \$5.23/CY x 231 CY = \$1,208.
- 2.1.2) *Vegetation Reseeding:* The total area of the landfill is 125,000 SF or 2.86 acres x 0.10 = 0.286 acres. The unit cost to revegetate (seeding, fertilizing, and mulching) the area is \$2,500/acre. Therefore, the annual cost to revegetate 10% of the landfill area is 0.286 acres x \$2,500/acre = \$715.

#### *4.0) Site Maintenance*

- 4.1) *Repair of Surface Water Diversion Structures:* The existing storm water system transmits runoff to swales along the perimeter of the landfill, and then to ponds located at the toe of the slopes. These swales and ponds will be maintained and cleaned on an annual basis. Estimate lump cost of \$1,500 per year x 30-year closure period = \$45,000.
- 4.2) *Repair of Fences & Gates:* Fences, gates, signs, roadblocks etc. will be maintained and repaired on an annual basis. Estimate an annual cost of \$1,000 x 30-year closure period = \$30,000.

- 4.3) Other Site Maintenance: Estimate annual cost of \$1,000 for miscellaneous maintenance costs associated with the landfill. The total cost is  $\$1,000 \times 30\text{-year closure period} = \$30,000$ .

Huntington Industrial Landfill  
Landfill Closure Cost Estimate Worksheet  
April 27, 2006

Item	Unit Measure	Cost/Unit	No. Units	Total Cost	References
1.0 Engineering					
1.1 Topographic Survey	Lump	\$1,500.00	1	\$1,500.00	(2),(3)
1.2 Boundary Survey for Closure	Lump	\$1,000.00	1	\$1,000.00	(2),(3)
1.3 Site Evaluation	Lump	\$1,740.00	1	\$1,740.00	(2),(3)
1.4 Development of Plans	Lump	\$7,500.00	1	\$7,500.00	(2),(3)
1.5 Contract Administration Bidding and Award	Lump	\$6,000.00	1	\$6,000.00	(3)
1.6 Administrative Costs for the Certification of Final Cover and Closure Notice	Lump	\$2,250.00	1	\$2,250.00	(3)
1.7 Project Management; Construction Observation and Testing	Lump	\$16,500.00	1	\$16,500.00	(3)
1.8 Monitor Well Consultant Cost				N/A	(1)
1.9 Other Environmental Permit Costs				\$2,800.00	(2),(3)
<b>Subtotal</b>				<b>\$39,290.00</b>	
<b>10 % Contingency</b>				<b>\$3,929.00</b>	
<b>Engineering Total</b>				<b>\$43,219.00</b>	

Item	Unit Measure	Cost/Unit	No. Units	Total Cost	References
2.0 Construction					
2.1 Final Cover System					
2.2 Completin of Top Cover					
2.2.1 Infiltration Layer (18")				\$0.00	
2.2.1a Soil Placement	CY	\$0.99	11575	\$11,459.25	(3)
2.2.1b Soil Processing (compaction)	CY	\$0.48	8681	\$4,166.88	(3)
2.2.1c Soil Amendment	CY			\$0.00	(3)
2.2.1d Soil Purchase	CY	\$7.60	11575	\$87,970.00	(3)
2.2.1e Transportation	TON	\$1.92	202	\$387.84	(3)
2.3 Revegetation					
2.3.1 Seeding	Acre	\$2,000.00	2.85	\$5,700.00	(2),(3)
2.3.2 Fertilize	Acre			\$0.00	(3)
2.3.3 Mulch	Acre			\$0.00	(3)
2.4 Site Grading and Drainage	S.Y.			\$0.00	(3)
2.5 Site Fencing and Security	L.F.			\$0.00	(3)
2.6 Leachate Collection System Completion				N/A	(1)

2.7 Completion of Gas Monitoring System				N/A	(1)
<b>Subtotal</b>				<b>\$109,683.97</b>	
<b>10% Contingency</b>				<b>\$10,968.40</b>	
<b>Construction Total</b>				<b>\$120,652.37</b>	

Item	Unit Measure	Cost/Unit	No. Units	Total Cost	
3.0 Gas Collection System					
3.1 System Design				N/A	(1)
3.2 Equipment and Installation				N/A	(1)
<b>Subtotal</b>				<b>\$0.00</b>	
<b>10% Contingency</b>				<b>\$0.00</b>	
<b>Gas Collection Total</b>				<b>\$0.00</b>	

Item	Unit Measure	Cost/Unit	No. Units	Total Cost	
4.0 Monitor Well Installation Cost					
4.1 Monitoring Well Installation				N/A	(1)
4.2 Piezometer and Monitor Well Plugging				N/A	(1)
<b>Subtotal</b>				<b>\$0.00</b>	
<b>10% Contingency</b>				<b>\$0.00</b>	
<b>Ground Water Installation Total</b>				<b>\$0.00</b>	

#### Calculation of Total Closure Costs

Engineering Total:	\$43,219.00	
Construction Total:	\$120,652.37	
Gas Collection Total:	\$0.00	
Ground Water Total:	\$0.00	
10% Contract Performance Bond:	\$16,387.14	(4)
SUBTOTAL:	\$180,258.50	
Legal Fees (10% Of Subtotal):	\$18,025.85	(5)
<b>TOTAL CLOSURE COSTS:</b>	<b>\$198,284.35</b>	

#### Reference Descriptions

- (1) Not Applicable for Class IIb landfills.
- (2) Engineering estimates based on similar projects.
- (3) Engineering estimates based on additional information and assumptions (See Attachment #1).
- (4) Contract performance bond includes, bond, insurance, taxes, etc.
- (5) Utah DSHW guidance recommends estimating up to 25% of total costs for legal fees.

Huntington Industrial Landfill  
Landfill Post-Closure Care Cost Estimate Worksheet  
April 27, 2006

Item	Unit Measure	Cost/Unit	No. Units	Total Cost	References
1.0 Engineering Costs					
1.1 Post-Closure Plan	Lump	\$5,750.00	1	\$5,750.00	(3)
1.2 Site Inspection and Record keeping (annual)	Lump/Year	\$1,380.00	30	\$41,400.00	(2),(3)
1.3 Correctional Plans and Specifications (annual)	Lump/Year	\$1,400.00	30	\$42,000.00	(2),(3)
1.4 Site Monitoring (semiannual) & Reporting				N/A	
1.4.1 Ground Water Monitoring				N/A	
1.4.1a Ground Water Sample Collection				N/A	(1)
1.4.1b Ground Water Sample Analysis				N/A	(1)
1.4.1c Ground Water Sample Analysis Review and Reporting				N/A	(1)
1.4.2 Landfill Gas Monitoring					
1.4.2a Gas Monitoring Data Collection				N/A	(1)
1.4.2b Gas Monitoring Data Review and Reporting				N/A	(1)
2.0 Maintenance Costs					
2.1 Cover Maintenance Costs					
2.1.1 Soil Replacement	Lump/Year	\$2,621.23	30	\$78,636.90	(3)
2.1.2 Vegetation Reseeding	Lump/Year	\$570.00	30	\$17,100.00	(3)
2.2 Equipment Maintenance					
2.2.1 Ground Water well Maintenance and Repair				N/A	(1)
2.2.2 Gas Collection System Operation				N/A	(1)
2.2.3 Gas Collection System Maintenance and Repair				N/A	(1)
2.2.4 Leachate Collection System Operation				N/A	(1)
2.2.5 Leachate Collection System Repair and Maintenance				N/A	(1)
3.0 Leachate Disposal				N/A	(1)

4.0 Site Maintenance					
4.1 Repair of Surface Water Diversion Structures	Lump/Year	\$1,500.00	30	\$45,000.00	(2),(3)
4.2 Repair of Fences and Gates	Lump/Year	\$1,000.00	30	\$30,000.00	(2),(3)
4.3 Other Site Maintenance	Lump/Year	\$1,000.00	30	\$30,000.00	(2),(3)
<b>Subtotal</b>				<b>\$289,886.90</b>	
<b>10% Contingency</b>				<b>\$28,988.69</b>	
<b>Post-Closure Care Total</b>				<b>\$318,875.59</b>	

#### **Total Closure and Post-Closure Costs**

Total Closure Costs:	\$198,284.35
Total Post-Closure Care Costs:	\$318,875.59
<b>Total Cost:</b>	<b>\$517,159.94</b>

#### **Reference Descriptions**

- (1) Note Applicable for Class IIIb landfills.
- (2) Engineering estimates based on similar projects.
- (3) Based on additional information and assumptions (See Attachment #1).

**Attachment #2. Earthwork Crew Descriptions**  
**Huntington Power Plant**  
**Industrial Landfill Closure & Post-Closure Cost Estimates**

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**Activity - Spread Cover Soil - Crew B-10M**

1 Equipment Operator (Medium)  
0.5 Laborer  
1 Dozer, 300 H.P.

**Activity - Compact Cover Soil - Crew B-10Y**

1 Equipment Operator (Medium)  
0.5 Laborer  
1 Vibratory Drum Roller

**Activity - Load Cover Soil - Crew B-10U**

1 Equipment Operator (Medium)  
0.5 Laborer  
1 Front End Loader, W.M., 5.5 CY

**Activity - Haul Cover Soil to Landfill - Crew B-34B**

1 Truck Driver (Heavy)  
1 Dump Truck, 16 Ton

**Activity - Seed, Mulch, & Fertilize Landfill - Crew B-81**

1 Laborer  
1 Equipment Operator (Medium)  
1 Truck Driver (Heavy)  
1 Hydromulcher, T.M.  
1 Tractor Truck, 4x2

**Notes:**

- (1) Crews were selected from RS MeansSite Work & Landscape Cost Data, 20th Edition
- (2) Revised costs for some tasks have received from 3rd party contractor; as a result, some crews listed for specific tasks will be determined by contractor.

**Appendix G.**  
**Financial Assurance**



Pacific Power | Utah Power  
Rocky Mountain Power  
825 NE Multnomah  
Portland, Oregon 97232

June 16, 2008

Mr. Dennis R. Downs  
Executive Secretary  
Division of Solid and Hazardous Waste  
Utah Department of Environmental Quality  
P. O. Box 144880  
Salt Lake City, UT 84114

Dear Mr. Downs,

I am the Chief Financial Officer of PacifiCorp, an Oregon Corporation, located at 825 NE Multnomah Street, Suite 2000, Portland, OR 97232. This letter is in support of the use of the financial test to demonstrate financial responsibility for closure, post-closure care, and corrective action as specified in (UAC) R315-309-3 (9).

The firm identified above is the owner or operator of the following facilities for which financial assurance is being demonstrated through the Corporate Financial Test as stated in Subsection R315-309-9 (2).

PacifiCorp  
Hunter Plant  
Hwy. 10 South of Castle Dale  
Castle Dale, UT

Hunter Industrial Landfill Site:	
Cost estimate for closure	\$885,726
Cost estimate for post-closure	\$902,154
Cost estimate for corrective action	\$0
Subtotal	\$1,787,880

PacifiCorp  
Huntington Plant  
Hwy. 31 West of Huntington  
Huntington, UT

Hunter Industrial Landfill Site:	
Cost estimate for closure	\$198,284
Cost estimate for post-closure	\$318,875
Cost estimate for corrective action	\$0
Subtotal	\$517,159

PacifiCorp  
Advance Ross  
Head of the Thea Foss Waterway  
Tacoma, WA

Subtotal	\$5,700,000
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PacifiCorp  
Idaho Falls Pole Yard  
2200 Leslie Avenue  
Idaho Falls, ID 83402  
EPA ID No. IDD000602631

Subtotal	\$1,253,360
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PacifiCorp  
American Barrel Site  
600 West South Temple  
Salt Lake City, UT 84104  
EPA ID No. UTD980667240

Subtotal \$10,583,000

Total environmental cost estimates,  
including obligations covered by a  
financial test \$19,841,399

This firm is required to file Form 10K with the Securities and Exchange Commission (SEC) for the latest fiscal year.

The fiscal year of this firm ends on March 31. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year ended March 31, 2005.

**Alternative II**

Current bond rating of most recent issuance and name of rating service  
for senior unsubordinated debt, as specified in R315-309-9(2)(a)(i) Standard & Poor's  
A-

Date of issuance bond August 24, 2004

Date of maturity bond August 15, 2034

\*Tangible net worth, as specified in R315-309-  
9(2)(b)(i), is greater than the sum of all  
liabilities shown above plus \$10 million: Yes \$3,077,700,000

\*Total assets in the U.S., as specified in R315-  
309-9(2)(c), are greater than or equal to the  
sum of all liabilities shown above: Yes \$12,520,900,000

If you have any questions, please contact Tony Hiatt at (801) 220-2567.

Sincerely,

*Richard Peach*

Richard Peach  
Chief Financial Officer

June 26, 2006

Dated

## Report of Independent Accountants

To the Board of Directors and Management of  
PacifiCorp:

We have performed the procedures enumerated below, which were agreed to by PacifiCorp and the Utah Department of Environmental Quality Division of Solid and Hazardous Waste (together the "specified parties"), solely to assist the specified parties in evaluating PacifiCorp's compliance with the financial test option as of March 31, 2005, included in the accompanying letter dated June 16, 2006 from Mr. Richard Peach, Chief Financial Officer of PacifiCorp (the "Letter"). PacifiCorp management is responsible for PacifiCorp's compliance with those requirements. This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. The sufficiency of these procedures is solely the responsibility of those parties specified in this report. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

In respect of the Letter:

1. We agreed the balance included with the caption "Tangible net worth" to a schedule ("the Schedule") prepared by PacifiCorp, which is derived from the consolidated financial statements included in PacifiCorp's Annual Report on Form 10-K filed with the Securities and Exchange Commission with the exception of "intangible assets," which is derived directly from PacifiCorp's accounting records. We agreed the Schedule to the consolidated financial statements and accounting records of PacifiCorp.

The definition of "Tangible net worth" is outlined in Utah Department of Environmental Quality Solid Waste Rule R315-309-9(1)(i) as follows: "Tangible net worth" means the tangible assets that remain after deducting liabilities; such assets would not include intangibles such as goodwill and rights to patents or royalties.

In applying this definition, PacifiCorp management has interpreted the term "tangible assets" as being total assets less intangible plant (net of accumulated amortization).

2. We agreed the balance included with the caption "Total assets in the U.S." to the consolidated financial statements, as rounded, and accounting records of PacifiCorp. The definition of "Total assets in the U.S." is outlined in Utah Department of Environmental

Quality Solid Waste Rule R315-309-9(1)(a) as follows: "Assets" means all existing and probable future economic benefits obtained or controlled by a particular entity.

We were not engaged to and did not conduct an examination, the objective of which would be the expression of an opinion on the Letter. Accordingly, we do not express such an opinion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information and use of PacifiCorp and the Utah Department of Environmental Quality Division of Solid and Hazardous Waste, and is not intended to be and should not be used by anyone other than these specified parties.

*PricewaterhouseCoopers LLP*

June 16, 2006

**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**  
**Washington, D.C. 20549**

**FORM 10-K**

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended March 31, 2006**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from \_\_\_\_\_ to \_\_\_\_\_**

**Commission File Number 1-5152**

**PACIFICORP**

(Exact name of registrant as specified in its charter)

**State of Oregon**

(State or other jurisdiction  
of incorporation or organization)

**93-0246090**

(I.R.S. Employer Identification No.)

**825 N.E. Multnomah Street, Portland, Oregon**

(Address of principal executive offices)

**97232**

(Zip Code)

**(503) 813-5000**

(Registrant's telephone number)

**Securities registered pursuant to Section 12(g) of the Act:**

**Title of each Class**

5% Preferred Stock (Cumulative; \$100 Stated Value)

Serial Preferred Stock (Cumulative; \$100 Stated Value)

No Par Serial Preferred Stock (Cumulative; \$100 Stated Value)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [ ]

No [X]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes [ ]

No [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X]

No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act).

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

<u>Class</u>	<u>Outstanding at May 19, 2006</u>
Common Stock, no par value	357,060,915 shares

All shares of outstanding common stock are indirectly owned by MidAmerican Energy Holdings Company, 666 Grand Avenue, Des Moines, Iowa.

**DOCUMENTS INCORPORATED BY REFERENCE**

None.

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## DEFINITIONS

When the following terms are used in the text, they will have the meanings indicated:

<u>Term</u>	<u>Meaning</u>
CPUC.....	California Public Utilities Commission
FERC.....	Federal Energy Regulatory Commission
IPUC.....	Idaho Public Utilities Commission
kWh.....	Kilowatt-hour(s), one kilowatt continuously for one hour
MEHC.....	MidAmerican Energy Holdings Company, an Iowa corporation and indirect parent company of PacifiCorp
MW.....	Megawatt
MWh.....	Megawatt-hour(s), one megawatt continuously for one hour
OPUC.....	Oregon Public Utility Commission
PacifiCorp.....	PacifiCorp, an Oregon corporation and direct, wholly owned subsidiary of PPW Holdings LLC
PHI.....	PacifiCorp Holdings, Inc., a Delaware corporation and non-operating United States holding company and the former direct parent company of PacifiCorp
PPW Holdings LLC	PPW Holdings LLC, the direct parent company of PacifiCorp
ScottishPower.....	Scottish Power plc, the former ultimate, indirect parent company of PHI and PacifiCorp
SEC.....	Securities and Exchange Commission
SFAS.....	Statement of Financial Accounting Standards
UPSC.....	Utah Public Service Commission
WPSC.....	Wyoming Public Service Commission
WUTC.....	Washington Utilities and Transportation Commission

## **PART I**

### **ITEM 1. BUSINESS**

#### **OVERVIEW**

##### **Ownership by MEHC; Sale of PacifiCorp**

On March 21, 2006, MidAmerican Energy Holdings Company ("MEHC") completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. ("PHI"), a subsidiary of Scottish Power plc ("ScottishPower"), pursuant to the Stock Purchase Agreement among MEHC, ScottishPower and PHI dated May 23, 2005, as amended on March 21, 2006 (the "Stock Purchase Agreement"). The cash purchase price was \$5.1 billion. PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities, which include both common and preferred stock. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). All descriptions of the terms of the Stock Purchase Agreement contained in this Annual Report are modified in their entirety by reference to the terms of such agreement, which is included as an exhibit hereto.

##### **Operations**

PacifiCorp is a regulated electricity company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. As a vertically integrated electric utility, PacifiCorp owns or has contracts for fuel sources such as coal and natural gas and uses these fuel sources, as well as wind, geothermal and water resources, to generate electricity at its power plants. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines throughout PacifiCorp's six-state region. The electricity is then transformed to lower voltages and delivered to customers through PacifiCorp's distribution system. PacifiCorp sells electricity primarily in the retail market, with sales to residential, commercial and industrial customers. PacifiCorp also sells electricity in the wholesale market in connection with excess electricity generation or balancing activities. Subsidiaries of PacifiCorp support its electric utility operations by providing coal mining and other fuel-related services, as well as environmental remediation. PacifiCorp's goal is to provide safe, reliable, low-cost electricity to its customers, with fair and increasing earnings to its common shareholder. PacifiCorp expects that costs prudently incurred to provide service to its customers will be included as allowable costs for state rate-making purposes.

Following the closing of PacifiCorp's sale, MEHC announced a new organizational structure under the direction of a newly appointed chairman and chief executive officer, who oversees the company's entire operations. The PacifiCorp Energy operational unit is responsible for PacifiCorp's electric generation, commercial and energy trading, and coal-mining functions. The Pacific Power operational unit is responsible for delivering electricity to customers in Oregon, Washington and California. The Rocky Mountain Power operational unit is responsible for delivering electricity to customers in Utah, Wyoming and Idaho.

##### **Regulation**

PacifiCorp is subject to comprehensive regulation by the Federal Energy Regulatory Commission (the "FERC"), the Utah Public Service Commission (the "UPSC"), the Oregon Public Utility Commission (the "OPUC"), the Wyoming Public Service Commission (the "WPSC"), the Washington Utilities and Transportation Commission (the "WUTC"), Idaho Public Utility Commission (the "IPUC"), the California Public Utilities Commission (the "CPUC"), and other federal, state and local regulatory agencies. These agencies regulate many aspects of PacifiCorp's business, including customer rates, service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, wholesale sales and purchases of electricity, and the operation of its electric generation and transmission facilities.

##### **Employees**

On March 31, 2006, PacifiCorp had 6,750 employees, 58.4% of which were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America, International Brotherhood of Boilermakers and the United Mine Workers of America.

### Location and Information Requests

The location of PacifiCorp's principal offices is 825 N.E. Multnomah Street, Portland, Oregon 97232. PacifiCorp's website address is [www.pacifiCorp.com](http://www.pacifiCorp.com). PacifiCorp makes available free of charge, on or through its website, its annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing such reports with the United States Securities and Exchange Commission (the "SEC"). Information contained on PacifiCorp's website is not part of this report. Reports and other information regarding PacifiCorp that are required to be filed with the SEC may also be obtained from the SEC's website at [www.sec.gov](http://www.sec.gov).

## POWER AND FUEL SUPPLY

### Generating Plants

PacifiCorp owns, or has interests in, the following types of electricity generating plants:

	Plants	Nameplate Rating (MW)	Net Plant Capability (MW)
Coal	11	6,585.9	6,104.4
Natural gas and other	6	1,348.7	1,174.0
Hydroelectric	51	1,083.6	1,159.4
Wind	1	32.6	32.6
Total	69	9,050.8	8,470.4

The natural gas and other plants include the Currant Creek Power Plant, which commenced full combined-cycle operation in March 2006, adding 523.0 megawatts ("MW") of capability to PacifiCorp's generation portfolio.

The following table shows the estimated percentage of PacifiCorp's total energy requirements supplied by its generation plants and through short- and long-term contracts or spot market purchases during the years ended March 31, 2006, 2005 and 2004. See "Wholesale Sales and Purchased Electricity" below for more information.

	Years Ended March 31,		
	2006	2005	2004
Coal	67.5 %	67.3 %	67.8 %
Natural gas and other	4.3	4.8	4.7
Hydroelectric	6.2	4.6	5.4
Wind	0.2	0.2	0.2
Total energy generated	78.2	76.9	78.1
Purchase and exchange contracts	21.8	23.1	21.9
Total	100.0 %	100.0 %	100.0 %

The share of PacifiCorp's energy requirements generated by its plants will vary from year to year and is determined by factors such as planned and unplanned outages, availability and price of coal and natural gas, precipitation and snowpack levels, environmental considerations and the market price of electricity.

### Coal

As of March 31, 2006, PacifiCorp had an estimated 248.3 million tons of recoverable coal reserves in mines owned or leased by it. During the year ended March 31, 2006, these mines supplied 32.3% of PacifiCorp's total coal requirements, compared to 28.6% during the year ended March 31, 2005 and 30.4% during the year ended March 31, 2004. The remaining coal requirements are acquired through other long-term and short-term contracts. PacifiCorp-owned mines are located adjacent to many of its coal-fired generating plants, which significantly reduces overall transportation costs included in fuel expense. For further information, see "Item 2. Properties."

In an effort to lower costs and obtain better quality coal, the Jim Bridger Mine is in the process of developing an underground mine to access 57.0 million tons of PacifiCorp's coal reserves. Underground mine development and limited coal production began during the year ended March 31, 2005 and sustained operations are expected to begin by March 31, 2007. The life of the underground mine is expected to be approximately 15 years.

## **Natural Gas**

PacifiCorp currently utilizes natural gas to fuel four owned and one leased generating plants (composed of 16 generating units) that, at full capacity, require a maximum of 324,000 MMBtu (million British thermal units) of natural gas per day.

Additional electric generation resources required by PacifiCorp's Integrated Resource Plans discussed below, including the Lake Side Power Plant, could increase the natural gas requirement to 415,000 MMBtu per day or more. PacifiCorp has entered into transportation contracts to facilitate movement of natural gas to the Lake Side Power Plant. These contracts reflect PacifiCorp's fuel strategy that focuses on the management and mitigation of risks associated with supplying natural gas.

The growth of PacifiCorp's natural gas requirements requires a prudent, disciplined and well-documented approach to natural gas procurement and hedging. PacifiCorp has developed a natural gas strategy that addresses the need to economically hedge the commodity risk (physical availability and price), the transportation risk and the storage risk associated with its forecasted and potentially growing natural gas requirements. This natural gas strategy, combined with the prospect for increasing natural gas requirements, is expected to increase the volume and types of PacifiCorp's procurement and economic hedging activity.

PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives. As of March 31, 2006, PacifiCorp had economically hedged 100.0% of its forecasted physical and financial exposure for the remainder of calendar 2006 and had economically hedged 100.0% of its forecasted physical and financial exposure for calendar 2007. For calendar 2008, PacifiCorp currently has hedged 88.0% of its physical exposure and 96.0% of its financial exposure. This economic hedging includes the additional supply requirements arising from the Lake Side Power Plant and the recently constructed Currant Creek Power Plant.

## **Hydroelectric**

PacifiCorp's hydroelectric portfolio consists of 51 plants with a net plant capability of 1,159.4 MW. These plants account for approximately 14.0% of PacifiCorp's total generating capacity, helping satisfy a significant portion of PacifiCorp's reserve requirements and providing operational benefits such as flexible generation and voltage control. Hydroelectric plants are located in the following states: Utah, Oregon, Wyoming, Washington, Idaho, California and Montana.

The amount of electricity PacifiCorp is able to generate from its hydroelectric plants depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watersheds, plant availability and restrictions imposed by oversight bodies due to competing water management objectives. When these factors are favorable, PacifiCorp can generate more electricity using its hydroelectric plants. When these factors are unfavorable, PacifiCorp must increase its reliance on more expensive thermal plants and purchased electricity.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses from the FERC. These licenses are granted by the FERC for periods of 30 to 50 years. Several of PacifiCorp's long-term operating licenses have expired or will expire in the next few years. Hydroelectric facilities operating under expired licenses may operate under annual licenses granted by the FERC until new operating licenses are issued. Hydroelectric relicensing and the related environmental compliance requirements are subject to a degree of uncertainty. PacifiCorp expects that future costs relating to these matters may be significant and consist primarily of additional relicensing costs and capital expenditures. Electricity generation reductions may also result from additional environmental requirements. At March 31, 2006, PacifiCorp had incurred \$70.3 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. See "Hydroelectric Relicensing" and "Hydroelectric Decommissioning" both discussed below.

## **Wind and Other Renewable Resources**

PacifiCorp is pursuing renewable power as a viable, economic and environmentally prudent means of generating electricity. The benefits of renewable energy include low to no emissions and no fossil fuel requirements. Resources such as wind and solar are intermittent, so complementary thermal or hydroelectric resources are important to integrating intermittent renewable resources into the electric system.

PacifiCorp acquires wind and other renewable power through one PacifiCorp-owned wind farm in Wyoming and various purchased electricity agreements with wind farms in Oregon and Wyoming, as well as with renewable facilities classified as "qualifying facilities" under the Public Utility Regulatory Policies Act. PacifiCorp also owns a geothermal plant in Utah. For the year ended March 31, 2006, PacifiCorp received 256,371 MWh from its owned wind farm and geothermal plant. In this same period, 303,158 MWh were purchased from other wind sources, not including qualifying facilities.

To encourage the use of wind energy, PacifiCorp has generation, storage and delivery agreements with various other utilities. For the year ended March 31, 2006, electricity generated for delivery to customers under these agreements totaled 532,103 MWh in addition to the wind energy generated or purchased for PacifiCorp's own use.

In connection with its sale to MEHC, PacifiCorp has committed to state regulatory commissions that it will bring at least 100.0 MW of cost-effective wind resources in service by March 21, 2007 and, to the extent available, add 400.0 MW, inclusive of the 100.0 MW commitment, of cost-effective renewable resources in PacifiCorp's generation portfolio by December 31, 2007.

## **Future Generation and Conservation**

### **Integrated Resource Plans**

As required by state regulators, PacifiCorp uses Integrated Resource Plans to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The Integrated Resource Plan process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts and other factors. The Integrated Resource Plan is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. Each state commission that has Integrated Resource Plan adequacy rules judges whether the Integrated Resource Plan reasonably meets its standards and guidelines at the time the Integrated Resource Plan is filed. If the Integrated Resource Plan is found to be adequate, then it is formally "acknowledged." The Integrated Resource Plan can then be used as evidence by parties in rate-making or other regulatory proceedings.

In November 2005, PacifiCorp released an update to its 2004 Integrated Resource Plan. The updated 2004 Integrated Resource Plan identified a need for approximately 2,113.0 MW of additional resources by summer 2014, to be met with a combination of thermal generation (1,936.0 MW) and load control programs (177.0 MW). PacifiCorp also planned to implement energy conservation programs of 450.0 average MW, to continue to seek procurement of 1,400.0 MW of economic renewable resources and to use wholesale electricity transactions to make up for the remaining difference between retail load obligations and available resources.

In addition to new generation resources, substantial transmission investments could be required to deliver power to customers and provide system reliability. The actual investment requirement will depend on the location and other characteristics of the new generation resources. See "Transmission and Distribution" discussion below.

## **WHOLESALE SALES AND PURCHASED ELECTRICITY**

In addition to its portfolio of generating plants, PacifiCorp purchases electricity in the wholesale markets to meet its retail load obligations, long-term wholesale obligations, and energy and capacity balancing requirements. For the year ended March 31, 2006, 21.8% of PacifiCorp's energy requirements were supplied by purchased electricity under short- and long-term purchase arrangements, both as defined by the FERC. PacifiCorp's energy requirements supplied by purchased electricity under short- and long-term purchase arrangements were 23.1% for the year ended March 31, 2005 and 21.9% for the year ended March 31, 2004.

Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility. PacifiCorp enters into wholesale purchase and sale transactions to balance its supply when generation and retail loads are higher or lower than expected. Generation varies with the levels of outages, hydroelectric generation conditions and transmission constraints. Retail load varies with the weather, distribution system outages, consumer trends and the level of economic activity. In addition, PacifiCorp purchases electricity in the wholesale markets when it is more economical than generating it at its own plants. PacifiCorp may also sell into the wholesale market excess electricity arising from imbalances between generation and retail load obligations, subject to pricing and transmission constraints.

PacifiCorp's wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long term. Historically, PacifiCorp has been able to purchase electricity from utilities in the western United States for its own requirements. These purchases are conducted through PacifiCorp and third party transmission systems, which connect with market hubs in the Pacific Northwest to provide access to normally low-cost hydroelectric generation and in the southwestern United States to provide access to normally higher-cost fossil-fuel generation. The transmission system is available for common use consistent with open-access regulatory requirements.

## TRANSMISSION AND DISTRIBUTION

Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers. PacifiCorp plans, builds and operates a transmission system. During the year ended March 31, 2006, PacifiCorp delivered 67,810,861 MWh of electricity to customers in its two control areas through 15,580 miles of transmission lines and its 59,510 mile system of distribution lines. For further detail, see "Item 2. Properties – Transmission and Distribution."

PacifiCorp's transmission system is part of the Western Interconnection, the regional grid in the west. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico that make up the Western Electric Coordinating Council. The map under "Service Territories" below shows PacifiCorp's transmission grid. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements. Due to PacifiCorp's continuing commitment to improve customer service and network safety and to enhance system reliability and performance, PacifiCorp has focused on infrastructure improvement projects in targeted areas. PacifiCorp and MEHC have committed to a number of transmission and distribution system investments in connection with regulatory approval of PacifiCorp's sale to MEHC. For discussion of specific planned spending see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation – Liquidity and Capital Resources – Future Uses of Cash – Capital Expenditure Program."

PacifiCorp operates one control area on the western portion of its service territory and one control area on the eastern portion of its service territory. A control area is a geographic area with electric systems that control generation to maintain schedules with other control areas and ensure reliable operations. In operating the control areas, PacifiCorp is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the control area, plus net import power, matches customer loads. PacifiCorp also schedules power deliveries over its transmission system and maintains reliability in part by verifying that customers are properly using the system within established bounds.

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff. In accordance with the Open Access Transmission Tariff, PacifiCorp offers several transmission services to wholesale customers:

- Network transmission service (guaranteed service that integrates generating resources to serve retail loads);
- Long-term and short-term firm point-to-point transmission service (guaranteed service with fixed delivery and receipt points); and
- Non-firm point-to-point service ("as available" service with fixed delivery and receipt points).

These services are offered on a non-discriminatory basis, meaning that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from the generating and marketing business in accordance with the FERC Standards of Conduct. Transmission costs are not separated from, but rather are "bundled" with, generation and distribution costs in retail rates approved by state regulatory

commissions. See "Regulation – Federal Regulatory Matters" below for further information related to the Energy Policy Act of 2005, which requires that the FERC establish and enforce standards for electric reliability.

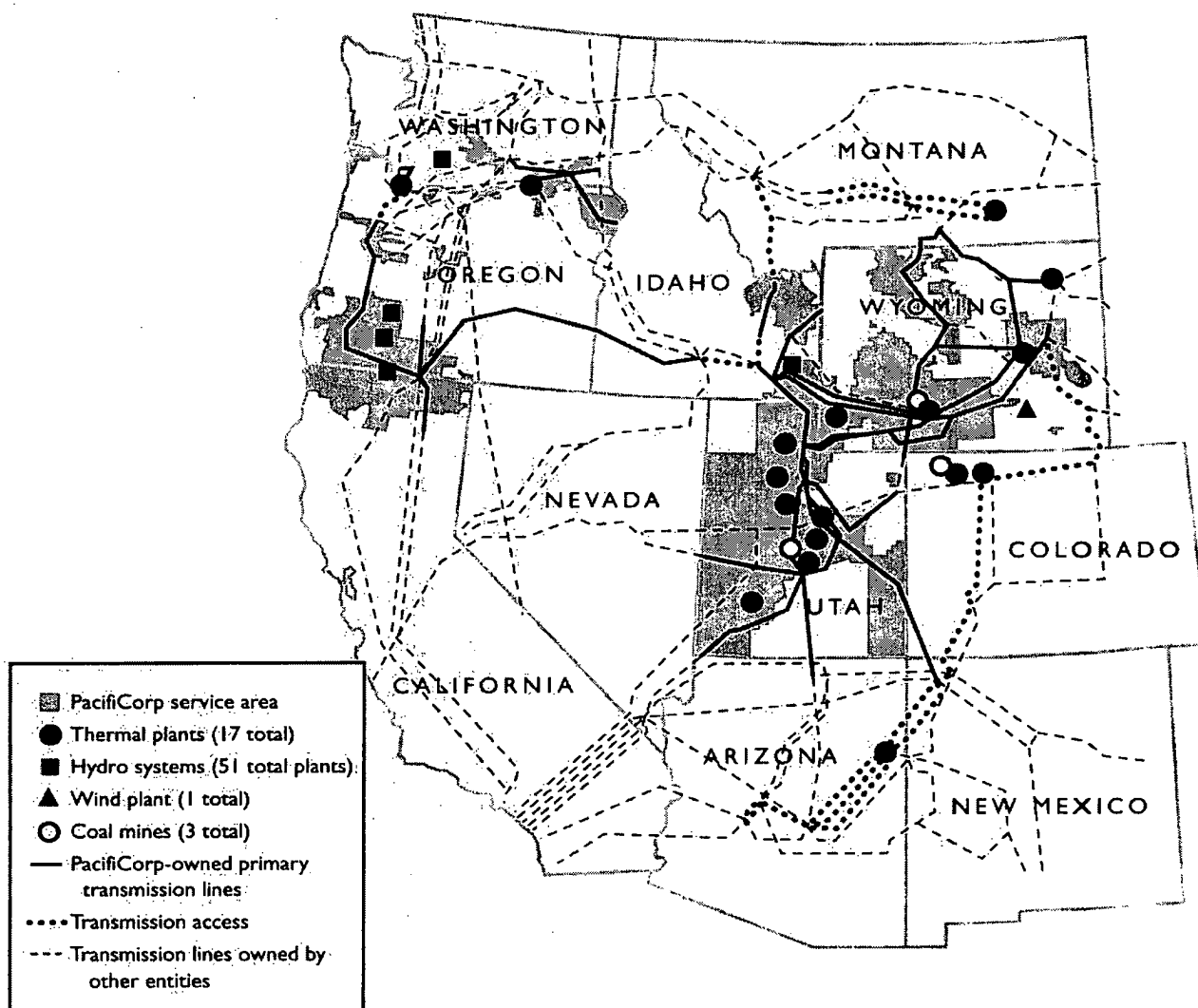
### **Regional Transmission Coordination**

In December 1999, the FERC encouraged all companies with transmission assets to form regional transmission organizations that would manage certain operational functions of the transmission grid and plan for necessary expansion. In response, several northwest utilities, including PacifiCorp, formed a regional transmission entity, known as Grid West, that was intended to coordinate transmission functions in all or portions of eight western states and western Canada.

In April 2006, the Grid West board voted to dissolve the Grid West entity. This decision resulted primarily from the decision of key participants, including the Bonneville Power Administration to discontinue support and funding of Grid West efforts. To address the continuing need for some degree of regional transmission coordination, PacifiCorp and the other parties are considering smaller-scale initiatives that could provide value for customers.

### **SERVICE TERRITORIES**

PacifiCorp serves approximately 1.6 million retail customers in service territories aggregating approximately 136,000 square miles in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho and California. The combined service territory's diverse regional economy ranges from rural, agricultural and mining areas to urbanized manufacturing and government service centers. No single segment of the economy dominates the service territory, which mitigates PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, mainly consisting of Utah, Wyoming and southeast Idaho, the principal industries are manufacturing, health services, recreation and mining or extraction of natural resources. In the western portion of the service territory, mainly consisting of Oregon, southeastern Washington and northern California, the principal industries are agriculture and manufacturing, with forest products, food processing, high technology and primary metals being the largest industrial sectors. The following map highlights PacifiCorp's retail service territory, plant locations and PacifiCorp's primary transmission lines. PacifiCorp's generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through the transmission lines owned by others. See "Item 2. Properties" for additional information on PacifiCorp's plants.



The geographic distribution of PacifiCorp's retail electric operating revenues for the years ended March 31, 2006, 2005 and 2004 was as follows:

	Years Ended March 31,		
	2006	2005	2004
Utah	40.9 %	40.6 %	38.5 %
Oregon	29.3	29.3	31.5
Wyoming	13.3	13.6	12.8
Washington	8.4	8.0	8.4
Idaho	5.7	6.1	6.3
California	2.4	2.4	2.5
	<u>100.0 %</u>	<u>100.0 %</u>	<u>100.0 %</u>

PacifiCorp receives authorization from state public utility commissions to serve areas within each state. This authorization is perpetual until withdrawn by the state public utility commissions. In addition, PacifiCorp has received franchises to provide electric service to customers inside incorporated areas within the states. Most franchises have terms of five years or more, but some have indefinite terms. PacifiCorp must renew franchises that expire. Governmental agencies have the right

to challenge PacifiCorp's right to serve in a specific area and can condemn PacifiCorp's property under certain circumstances in accordance with the laws in each state. However, PacifiCorp vigorously challenges any attempts from individuals and governmental entities to undertake forced takeover of any portions of its service territory. PacifiCorp is subject to energy regulation, legislation and political risks. Any changes in regulations and rates or legislative developments may adversely affect its business, financial condition, results of operations and cash flows. See "Item 1A. Risk Factors" for further information.

## CUSTOMERS

Electricity sold to retail customers and the number of retail customers, by class of customer, for the years ended March 31, 2006, 2005 and 2004, were as follows:

	Years Ended March 31,					
	2006		2005		2004	
(Thousands of MWh)						
MWh sold						
Residential	14,880	29.7 %	14,117	28.9 %	14,460	29.7 %
Commercial	14,887	29.7	14,642	29.9	14,413	29.6
Industrial	19,746	39.4	19,454	39.8	19,133	39.3
Other	599	1.2	706	1.4	673	1.4
Total MWh sold	50,112	100.0 %	48,919	100.0 %	48,679	100.0 %
Number of retail customers (in thousands)						
Residential	1,404	85.6 %	1,373	85.5 %	1,341	85.4 %
Commercial	198	12.1	194	12.1	190	12.1
Industrial	34	2.1	34	2.1	34	2.2
Other	4	0.2	4	0.3	5	0.3
Total	1,640	100.0 %	1,605	100.0 %	1,570	100.0 %
Retail customers						
Average annual usage per customer (kWh)	30,895		30,825		31,305	
Average annual revenue per customer	\$ 1,732		\$ 1,669		\$ 1,638	
Revenue per kWh	5.6¢		5.4¢		5.2¢	

During the year ended March 31, 2006, no single retail customer accounted for more than 2.0% of PacifiCorp's retail electric revenues, and the 20 largest retail customers accounted for 13.0% of PacifiCorp's retail electric revenues.

PacifiCorp is estimating average growth in retail megawatt-hour ("MWh") sales in PacifiCorp's franchise service territories to average between 2.0% and 3.0% annually over the five years to December 2010, depending on factors such as economic conditions, number of customers, weather, consumer trends, conservation efforts and changes in prices.

## Seasonality

As a result of the geographically diverse area of operations, PacifiCorp's service territory has historically experienced complementary seasonal load patterns. In the western portion, customer demand peaks in the winter months due to heating requirements. In the eastern portion, customer demand peaks in the summer when irrigation and air-conditioning systems are heavily used.

For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Strong Utah residential growth over the last several years and increasing installations of central air conditioning systems are contributing to faster summer peak growth.

## RETAIL COMPETITION

During the year ended March 31, 2006, PacifiCorp continued to operate its retail business under state regulation, which generally prohibits retail competition. However, certain of PacifiCorp's commercial and industrial customers in Oregon have the right to choose alternative electricity suppliers. As a result of Direct Access mandated by Oregon's Senate Bill 1149, a group of customers having a total average load of approximately 11.4 average MW have chosen service from suppliers other than PacifiCorp. A group of customers having a total average load of approximately 1.6 average MW have taken service from PacifiCorp at the Daily Market Pricing Option. This service provides a market-based pricing option by linking the energy charge on a customer's bill to a representative market price index. PacifiCorp does not expect the Direct Access program and the Daily Market Pricing Option to have a material effect on earnings for the 12 months ending March 31, 2007.

In addition to Oregon's Direct Access program, others in PacifiCorp's service territories are seeking to have a choice of suppliers, exploring options to build their own generation or co-generation plants, or considering the use of alternative energy sources such as natural gas. If these customers gain the right to receive electricity from alternative suppliers, they will make their energy purchasing decisions based upon many factors, including price, service and system reliability. The use of alternative energy sources is typically based on availability, price and the general demand for electricity.

Any adoption of retail competition by the legislatures in the states served by PacifiCorp, in addition to the Direct Access program, and/or the unbundling of transmission, distribution and generation costs in regulated electricity services could have a significant adverse financial impact on PacifiCorp due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital and could result in increased pressure to lower the price of electricity. Although PacifiCorp believes it will continue as a regulated entity and does not expect significant retail competition in the near future, it cannot predict if or to what extent it will be subject to changes in legislation or regulation allowing retail competitors, nor can PacifiCorp predict the impact of these changes. See "Item 1A. Risk Factors – PacifiCorp is subject to energy regulation, legislation and political risks, and changes in regulations and rates or legislative developments may adversely affect its business, financial condition, results of operations and cash flows."

## ENVIRONMENTAL MATTERS

PacifiCorp is subject to a number of federal, state and local environmental laws and regulations affecting many aspects of its present and future operations. These requirements relate to air emissions, water quality, waste management, hazardous chemical use, noise abatement, land use aesthetics and endangered species.

Environmental laws and regulations currently have, and future modifications may have, the effect of (i) increasing the lead time for the construction of new facilities, (ii) significantly increasing the total cost of new facilities, (iii) requiring modification of PacifiCorp's existing facilities, (iv) increasing the risk of delay on construction projects, (v) increasing PacifiCorp's cost of waste disposal, and (vi) reducing the amount of energy available from PacifiCorp's facilities. Any of these items could have a substantial impact on amounts required to be expended by PacifiCorp in the future.

In the year ended March 31, 2006, PacifiCorp spent approximately \$62.3 million on environmental capital projects. PacifiCorp currently estimates expenditures for environmental-related capital projects will total approximately \$129.2 million in the 12 months ending March 31, 2007.

### Air Quality

PacifiCorp's fossil fuel-fired electricity generation plants are subject to applicable provisions of the Clean Air Act and related air quality standards promulgated by the United States Environmental Protection Agency ("EPA") and state air quality laws. The Clean Air Act provides the framework for regulation of certain air emissions and permitting and monitoring associated with those emissions. PacifiCorp owns or has interests in 11 coal-fired generating plants, which represent 72.1% of PacifiCorp's generating capability. PacifiCorp believes it has all required permits and other approvals to operate its plants and that the plants are in material compliance with applicable requirements.

The acquisition of PacifiCorp by MEHC includes a regulatory commitment to spend approximately \$812.0 million over several years to reduce emissions at PacifiCorp's generating facilities to address existing and future air quality requirements. These costs and any additional expenditures necessitated by air quality regulations are expected to be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated results of operations.

The EPA has in recent years implemented more stringent national ambient air quality standards for ozone and new standards for fine particulate matter. These standards set the minimum level of air quality that must be met throughout the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment of the standard. Areas that fail to meet the standard are designated as being non-attainment areas. Generally, once an area has been designated as a non-attainment area, sources of emissions that contribute to the failure to achieve the ambient air quality standards are required to make emissions reductions. The EPA has concluded that Utah and Wyoming, where PacifiCorp's major emission sources are located, are in attainment of the ozone standards and the fine particulate matter standards.

In December 2005, the EPA proposed a revision of the ambient air quality standards for fine particles that would maintain the current annual standard and set a new, more stringent 24-hour standard for concentration of fine particulate. The EPA is scheduled to issue final rules in September 2006. Until the EPA takes final action on the proposal, the impact of the proposed rules on PacifiCorp cannot be determined.

In March 2005, the EPA released the final Clean Air Mercury Rule. The Clean Air Mercury Rule utilizes a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the current nationwide level of 48 tons to 15 tons at full implementation. The Clean Air Mercury Rule's two-phase reduction program requires initial reductions of mercury emissions in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70.0% by 2018. Individual states are required to implement the Clean Air Mercury Rule through their state implementation plans. Depending on the outcome of the respective states' implementation rules, the Clean Air Mercury Rule may require PacifiCorp to reduce emissions of mercury from some or all of its coal-fired facilities through the installation of emission controls, the purchase of emission allowances, or some combination thereof.

The Clean Air Mercury Rule could, in whole or in part, be superseded or made more stringent by one of a number of multi-pollutant emission reduction proposals currently under consideration at the federal level, including pending legislative proposals that contemplate 70.0% to 90.0% reductions of sulfur dioxide, nitrogen oxides and mercury, as well as possible new federal regulation of carbon dioxide and other gases that may affect global climate change. In addition to any federal legislation that could be enacted by the United States Congress to supersede the Clean Air Mercury Rule, the rules could be changed or overturned as a result of litigation. The sufficiency of the standards established by the Clean Air Mercury Rule has been legally challenged in the United States District Court for the District of Columbia. Until final resolution of litigation challenging the Clean Air Mercury Rule, the full impact of the rules on PacifiCorp cannot be determined.

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. PacifiCorp and other stakeholders are participating in the Western Regional Air Partnership to help develop the technical and policy tools needed to comply with this program.

Under existing New Source Review provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (i) beginning construction of a new stationary source of a New Source Review-regulated pollutant, or (ii) making a physical or operational change to an existing stationary source of such pollutants. Pending or proposed air regulations will require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxides and other pollutants below current levels. These reductions will be required to address regional haze programs, mercury emissions regulations and possible re-interpretations and changes to the federal Clean Air Act. In the future, PacifiCorp expects to incur significant costs to comply with various stricter air emissions requirements. These potential costs are expected to consist primarily of capital expenditures. PacifiCorp expects these costs would be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated results of operations. See also "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs."

The EPA has requested from several utilities information and supporting documentation regarding their capital projects for various generating plants. The requests were issued as part of an industry-wide investigation to assess compliance with the New Source Review and the New Source Performance Standards of the Clean Air Act. In 2001 and 2003, PacifiCorp received requests for information from the EPA relating to PacifiCorp's capital projects at seven of its generating plants. PacifiCorp submitted information responsive to the requests and there are currently no outstanding data requests pending from the EPA. PacifiCorp cannot predict the outcome of these requests at this time.

In 2002 and 2003, the EPA proposed various changes to its New Source Review rules that clarify what constitutes routine repair, maintenance and replacement for purposes of triggering New Source Review requirements. These changes have been subject to legal challenge and, until such time as the legal challenges are resolved and the rules are effective, PacifiCorp will continue to manage projects at its generating plants in accordance with the rules in effect prior to 2002. In October 2005, the EPA proposed a rule that would change or clarify how emission increases are to be calculated for purposes of determining the applicability of the New Source Review permitting program for existing power plants. The impact of these proposed changes on PacifiCorp cannot be determined until after the rule is finalized and implemented.

In February 2005, the Kyoto Protocol became effective, requiring 35 developed countries to reduce greenhouse gas emissions by approximately 5.0% between 2008 and 2012. While the United States did not ratify the protocol, the ratification and implementation of its requirements in other countries has resulted in increased attention to climate change in the United States. In 2005, the United States Senate adopted a "sense of the Senate" resolution that puts the United States Senate on record that the United States Congress should enact a comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that will not significantly harm the United States economy; and will encourage comparable action by other nations that are major trading partners and key contributors to global emissions. While debate continues at the national level over the direction of domestic climate policy, several states are developing state-specific or regional legislative initiatives to reduce greenhouse gas emissions. In December 2005, the states of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont signed a mandatory regional pact to reduce greenhouse gas emissions that would become effective in 2009 and ultimately would require a reduction in greenhouse gas emissions of 10.0% from 1990 levels. An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80.0% below 1990 levels by 2050. In addition, California is seeking to apply a greenhouse gas emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility.

Litigation was filed in the federal district court for the southern district of New York seeking to require reductions of carbon dioxide emissions from generating facilities of five large electric utilities. The court dismissed the public nuisance suit, holding that such critical issues affecting the United States such as greenhouse gas emissions reductions are not the domain of the court and should be resolved by the Executive Branch and the United States Congress. This ruling has been appealed to the Second Circuit Court of Appeals. The outcome of climate change litigation and federal and state initiatives cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could significantly impact PacifiCorp's fossil-fueled facilities and, therefore, its results of operations and cash flows. PacifiCorp includes a projected additional cost for carbon dioxide emissions in its Integrated Resource Plans when evaluating proposed new resources.

The EPA's regulation of certain pollutants under the Clean Air Act, and its failure to regulate other pollutants, is being challenged by various lawsuits brought by both individual state attorney generals and environmental groups. To the extent that these actions may be successful in imposing additional and/or more stringent regulation of emissions on fossil-fueled facilities in general and PacifiCorp's facilities in particular, such actions could significantly impact PacifiCorp's fossil-fueled facilities and, therefore, its results of operations and cash flows.

### **Water Quality**

The federal Clean Water Act and individual state clean-water regulations require a permit for the discharge of wastewater, including storm water runoff from electricity plants and coal storage areas, into surface water and groundwater. Additionally, PacifiCorp believes that it currently has, or has initiated the process to receive, all required water quality permits.

## **Endangered Species**

The federal Endangered Species Act of 1973 and similar state statutes protect species threatened with possible extinction. Protection of the habitat of endangered and threatened species makes it difficult and more costly to perform some of PacifiCorp's core activities, including the siting, construction and operation of new and existing transmission and distribution facilities, as well as thermal, hydroelectric and wind generation plants. In addition, issues affecting endangered species can impact the relicensing of existing hydroelectric generating projects. This can generally reduce the generating output and operational flexibility, and potentially increase the costs of operation, of PacifiCorp's own hydroelectric resources, as well as raise the price PacifiCorp pays to purchase wholesale electricity from hydroelectric facilities owned by others.

## **Environmental Cleanups**

Under the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act and similar state statutes, entities that dispose of, or arrange for the disposal of, hazardous materials may be liable for cleanup of the contaminated property. In addition, the current or former owners or operators of affected sites may be liable. PacifiCorp has been identified as a potentially responsible party in connection with a number of cleanup sites because of its current or past ownership or operation of certain properties or because PacifiCorp sent materials deemed to be hazardous to the property in the past. PacifiCorp has completed several cleanup actions and is actively participating in investigations and remediation actions at other sites. See "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs" for further discussion.

## **Mine Reclamation**

The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. PacifiCorp's mining operations are subject to these reclamation and closure requirements. Significant expenditures are being incurred for both ongoing and final reclamation. For further discussion, see "Item 2. Properties" and "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs."

## **REGULATION**

PacifiCorp conducts its business in conformance with a multitude of federal and state laws. PacifiCorp is also subject to the jurisdiction of public utility regulatory authorities in each of the states in which it conducts retail electric operations. These authorities regulate various matters, including customer rates, services, accounting policies and practices, allocation of costs by state, issuances of securities and other matters. In addition, PacifiCorp is a "licensee" and a "public utility" as those terms are used in the Federal Power Act and is therefore subject to regulation by the FERC as to accounting policies and practices, certain prices and other matters, including the terms and conditions of transmission service. Most of PacifiCorp's hydroelectric plants are licensed by the FERC as major projects under the Federal Power Act, and certain of these projects are licensed under the Oregon Hydroelectric Act.

## **Federal Regulatory Matters**

After several years of active consideration, in July 2005 the United States Congress approved legislation making significant changes in federal energy policy. The Energy Policy Act of 2005, enacted in August 2005, repealed the Public Utility Holding Company Act of 1935 and transferred regulatory oversight of public utility holding companies from the SEC to the FERC. The Energy Policy Act of 2005 also contains provisions to encourage investment in renewable and lower-emission coal generation, provides financial incentives and removes regulatory barriers for developers of new electric transmission facilities, establishes a process for the creation and enforcement of mandatory electric reliability standards, and authorizes license applicants and other parties to seek less costly and more efficient conditions imposed on federal hydroelectric power licenses.

See "Item 8. Financial Statements – Note 10 – Commitments and Contingencies" which is incorporated by reference into this Item 1.

Several of PacifiCorp's hydroelectric plants are in some stage of the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of four hydroelectric plants. The following summarizes the status of certain of these projects.

#### **Hydroelectric Relicensing**

##### **Klamath hydroelectric project** – (Klamath River, Oregon and California)

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 161.4-MW Klamath hydroelectric project. The FERC is scheduled to complete its required analysis by January 2007. The United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006; PacifiCorp filed alternatives to the federal agencies' proposal and challenges to its factual assumptions in April 2006. PacifiCorp continues to participate in the mediated settlement discussions with state and federal agencies, Native American tribes and other stakeholders in an effort to reach a comprehensive agreement on project relicensing.

##### **Lewis River hydroelectric projects** – (Lewis River, Washington)

PacifiCorp filed new license applications for the 136.0-MW Merwin and 240.0-MW Swift No. 1 hydroelectric projects in April 2004. An application for a new license for the 134.0-MW Yale hydroelectric project was filed with the FERC in April 1999. However, consideration of the Yale application was delayed pending filing of the Merwin and Swift No. 1 applications so that the FERC could complete a comprehensive environmental analysis.

In November 2004, PacifiCorp executed a comprehensive settlement agreement with 25 other parties including state and federal agencies, Native American tribes, conservation groups, and local government and citizen groups to resolve, among the parties, issues related to the pending applications for new licenses for PacifiCorp's Merwin, Swift No. 1 and Yale hydroelectric projects. As part of this settlement agreement, PacifiCorp has agreed to implement certain protection, mitigation and enhancement measures prior to and during a proposed 50-year license period. However, these commitments are contingent on ultimately receiving a license from the FERC that is consistent with the settlement agreement and other required permits. Other required permits include biological opinions and a water quality certification. At the earliest, the FERC is expected to make a final decision in August 2006.

##### **North Umpqua hydroelectric project** – (North Umpqua River, Oregon)

In October 2005, the new FERC license for the 136.5-MW North Umpqua hydroelectric project became final under the terms of the North Umpqua Settlement Agreement. Prior to this date, the license had been effective, but not final, because environmental groups had challenged its legality before the FERC and in federal court. In September 2005, the Ninth Circuit Court of Appeals issued an order upholding the new license. Since the Ninth Circuit Court's order was not appealed within the allowed time, all legal challenges of the FERC license order have been exhausted and the license is final for purposes of recording liabilities. PacifiCorp is committed, over the 35-year life of the license, to fund approximately \$48.4 million for environmental mitigation and enhancement projects. As a result of the license becoming final, PacifiCorp recorded additional liabilities and intangible assets in October 2005 amounting to a present value of \$11.2 million. At March 31, 2006, the liability recorded for all North Umpqua obligations amounted to a present value of \$21.8 million.

##### **Prospect hydroelectric project** – (Rogue River, Oregon)

In June 2003, PacifiCorp submitted a final license application to the FERC for the Prospect Nos. 1, 2 and 4 hydroelectric projects, which total 36.8 MW. The FERC is expected to complete its required analysis and issue a new license before the end of October 2006.

#### **Hydroelectric Decommissioning**

##### **Condit hydroelectric project** – (White Salmon River, Washington)

In September 1999, a settlement agreement to remove the 9.6-MW Condit hydroelectric project was signed by PacifiCorp, state and federal agencies and non-governmental agencies. Under the original settlement agreement, removal was expected to begin in October 2006, for a total cost to decommission not to exceed \$17.2 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal will not begin until October 2008 for a total cost to decommission not to exceed \$20.5 million, excluding inflation. The settlement agreement is contingent upon receiving an amended FERC license and removal order that is not materially inconsistent with the amended settlement agreement and other regulatory approvals. PacifiCorp is in the process of acquiring all necessary permits, within the terms and conditions of the amended settlement agreement.

## State Regulatory Actions

PacifiCorp is currently pursuing a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. A component of the regulatory program is the filing of Power Cost Adjustment Mechanisms ("PCAM"). PCAMs deal with changes in power costs occurring between rate cases. Power costs above or below the amounts built into rates are recovered from or returned to customers according to the provisions in the specific PCAM. The following discussion provides a state-by-state update.

### Utah

In March 2006, PacifiCorp filed a general rate case with the UPSC related to increased investments in Utah due to growing demand for electricity. PacifiCorp is seeking an increase of \$197.2 million annually, or 17.1%. If approved by the UPSC, the increase would take effect in December 2006. In April 2006, PacifiCorp filed a revised case reflecting the effects of PacifiCorp's sale to MEHC. The revised case reduced the original increase requested from \$197.2 million to \$194.1 million. The active parties in the case have stipulated to a new schedule in the rate case which allows completion of preliminary audits and an opportunity for settlement discussions prior to the hearings set in July 2006 to determine the proper test year. In November 2005, PacifiCorp filed a PCAM application. The Utah Industrial Energy Consumer Group has filed a motion to dismiss the PCAM application based on lack of delegated legislative authority. PacifiCorp does not believe the motion has merit and will oppose the motion in its reply due June 9, 2006. The PCAM proceeding is running concurrently with the March 2006 general rate case.

### Oregon

In April 2006, long-term special contracts for PacifiCorp's Klamath basin irrigation customers expired. Under the contracts, customers received power at rates less than PacifiCorp's average retail rates charged to other customers on general irrigation tariffs. Following expiration of these contracts, the OPUC issued an order authorizing the transition of Klamath basin irrigators to generally applicable cost-based rates.

In February 2006, PacifiCorp filed a general rate case request with the OPUC for approximately \$112.0 million, which represents a 13.2% overall increase. The request is related to investments in generation, transmission and distribution infrastructure and increases in fuel and general operating expenses, including the maintenance of low-cost but aging power plants. A procedural schedule has been established with a decision from the OPUC expected by December 2006.

In September 2005, Oregon's governor signed into law Senate Bill 408. This legislation is intended to address differences between income taxes collected by Oregon public utilities in retail rates and actual taxes paid by the utilities or consolidated groups in which utilities are included for income tax reporting purposes. This legislation authorizes an automatic adjustment to rates based on the taxes paid to governmental entities on or after January 1, 2006. The OPUC adopted a temporary rule in September 2005 to establish filing requirements for an annual tax report mandated by Senate Bill 408. The definitions adopted in the temporary rule would allocate a share of individual taxable losses of affiliate companies to the utility even when the consolidated tax group pays more taxes than the utility collects in retail rates. The temporary rule expired in March 2006. PacifiCorp is actively participating in the rulemaking process for adopting permanent rules required by Senate Bill 408.

In September 2005, the OPUC issued an order granting a general rate increase of \$25.9 million, or an average increase of 3.2%, effective October 2005. PacifiCorp filed its general rate case in November 2004, and following four partial stipulations with participating parties, PacifiCorp's requested revenue requirement increase was \$52.5 million. The OPUC's order reduced PacifiCorp's revenue requirement by \$26.6 million based on the OPUC's interpretation of Senate Bill 408. In October 2005, PacifiCorp filed with the OPUC a motion for reconsideration and rehearing of the rate order generally on the basis that the tax adjustment was not made in compliance with applicable law. With the motion, PacifiCorp also filed a deferred accounting application with the OPUC to track revenues related to the disallowed tax expenses. The OPUC granted PacifiCorp's motion for reconsideration and rehearing in December 2005 and is reconsidering whether Oregon Senate Bill 408 applies to the general rate case and, if it does, whether the tax adjustment ordered by the OPUC results in rates that are unconstitutional. A hearing and submissions of written briefs are scheduled to occur through May 2006. A decision is expected by summer 2006.

PacifiCorp filed an application in February 2005 for deferral of higher power costs incurred in calendar 2005 due to continuing poor hydroelectric conditions. PacifiCorp sought deferral of these costs to track for future recovery in rates. In

May 2005, this deferral application was suspended to allow parties to focus on a PCAM application filed by PacifiCorp in April 2005. Briefing in the PCAM proceeding was completed in January 2006 and a commission order is pending. In May 2006, the PCAM proceeding was stayed for 60 days at PacifiCorp's request.

## **Wyoming**

In March 2006, the WPSC approved an agreement that settled the general rate case filed by PacifiCorp in October 2005 and a separate request filed by PacifiCorp in December 2005 to recover increased costs of net wholesale purchased power used to serve Wyoming customers. The agreement provides for an annual rate increase of \$15.0 million effective March 1, 2006, an additional annual rate increase of \$10.0 million effective July 1, 2006, a PCAM and an agreement by the parties to support a forecast test year in the next general rate case application.

## **Washington**

In May 2005, PacifiCorp filed a general rate case request with the WUTC for approximately \$39.2 million annually. Hearings took place in January and February 2006 and this amount was reduced to approximately \$30.0 million. As part of the general rate case, PacifiCorp was also seeking to recover \$8.3 million in hydroelectric costs and was proposing that future hydroelectric and power cost volatility be recovered through a PCAM that was proposed as part of the general rate case. In April 2006, the WUTC issued an order denying PacifiCorp's request to increase retail rates. The WUTC determined that application of PacifiCorp's cost allocation methodology failed to satisfy the statutory requirements that resources must benefit Washington ratepayers.

In April 2006, PacifiCorp filed a petition for reconsideration of the order and requested an increase of not less than \$11.0 million. PacifiCorp also filed a limited rate request seeking a rate increase of approximately \$7.0 million, which represents a 2.99% increase in rates. PacifiCorp has requested that these dockets be consolidated so that the requested increase of not less than \$11.0 million can be achieved.

## **Idaho**

In February 2006, PacifiCorp filed a notice of intent to file a general rate case with the IPUC. A general rate case may be filed between 60 and 120 days after filing such a notice. Negotiations with certain Idaho customers are ongoing and the successful conclusion of such negotiations may preclude the need for a rate case filing. If filed, the rate case will seek a rate increase in Idaho to be effective beginning January 2007.

In July 2005, the IPUC issued an order approving a settlement of PacifiCorp's general rate case filed in January 2005 and granting a stipulated rate increase of \$5.8 million, or an average increase of 4.8%, effective September 16, 2005. On that date, unrelated pre-existing surcharges expired, so the net effect to customers of the \$5.8 million base increase was an increase in rates of \$2.1 million annually, or an average increase of 1.7%.

## **California**

In April 2006, long-term special contracts for PacifiCorp's Klamath basin irrigation customers expired. Under the contracts, customers received power at rates less than PacifiCorp's average retail rates charged to other customers on general irrigation tariffs. Following expiration of these contracts, the CPUC approved a joint proposal for a transition to standard tariff pricing.

In November 2005, PacifiCorp filed a general rate case with the CPUC for an increase of \$11.0 million annually, or an average increase of 15.6% related to increasing costs, including power costs and operating expenses, as well as significant needed capital investments. PacifiCorp's application also requests the implementation of an Energy Cost Adjustment Clause ("ECAC"), which like a PCAM allows for annual rate adjustments for changes in the level of net power costs, and a Post Test-Year Adjustment Mechanism ("PTAM"), which would allow annual rate adjustments for changes in operating costs and plant additions. These proposed adjustment mechanisms would operate outside the context of traditional general rate cases. In May 2006, PacifiCorp filed an update to this general rate case to account for the Klamath basin irrigation customers' transition plan and to update the filing for the expected cost savings as a result of the acquisition of PacifiCorp by MEHC. This updated filing resulted in a net requested average increase of \$12.8 million annually, or 18.9% for California customers.

## ITEM 1A. RISK FACTORS

The following are certain risks and other factors to be considered when evaluating PacifiCorp. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for a discussion of additional important risks and other factors.

***PacifiCorp is engaged in several large construction or expansion projects, the completion and expected cost of which is subject to significant risk, and PacifiCorp has significant funding needs related to its planned capital expenditures.***

PacifiCorp is engaged in several large construction or expansion projects, including construction of a new generating facility, the Lake Side Power Plant, in Utah and various capital projects related to transmission and distribution. In addition, in connection with PacifiCorp’s acquisition by MEHC, MEHC and PacifiCorp have committed to undertake several other capital expenditure projects, principally relating to environmental controls, transmission and distribution, renewable generating and other facilities. PacifiCorp expects to incur substantial construction, expansion and other capital expenditure costs over the next several years, including the recent regulatory commitments previously discussed. PacifiCorp depends upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If these funds are not available and/or if MEHC does not elect to provide any needed funding to PacifiCorp, PacifiCorp may need to postpone or cancel planned capital expenditures.

The completion of any or all of PacifiCorp’s pending, proposed or future construction or expansion projects is subject to substantial risk and may expose PacifiCorp to significant costs. PacifiCorp’s development or construction efforts on any particular project, or its capital expenditure program generally, may not be successful. If PacifiCorp is unable to complete the development or construction of any capital project, or if it decides to delay or cancel a project, it may not be able to recover its investment in that project.

Also, a proposed expansion or new project may cost more than planned to complete, and any excess costs, if related to a regulated asset and found to be imprudent, may not be recoverable in rates. The inability to successfully and timely complete a project or avoid unexpected costs may require PacifiCorp to perform under guarantees, and the inability to avoid unsuccessful projects or to recover any excess costs may materially affect PacifiCorp’s cash flows and results of operations.

***PacifiCorp is subject to certain operating uncertainties which may adversely affect its financial position, results of operations and cash flows.***

The operation of complex electric utility systems (including transmission and distribution) and power generating facilities that are spread over a large geographic area involves many risks associated with operating uncertainties and events beyond PacifiCorp’s control. These risks include the breakdown or failure of power generation equipment, transmission and distribution lines or other equipment or processes, unscheduled plant outages, work stoppages, transmission and distribution system constraints or outages, fuel shortages or interruptions, performance below expected levels of output, capacity or efficiency, the effects of changing government regulation, operator error and catastrophic events such as severe storms, fires, earthquakes, explosions or mining accidents. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. The realization of any of these risks could significantly reduce PacifiCorp’s revenues or significantly increase its expenses, thereby adversely affecting results of operations. For example, if PacifiCorp cannot operate generation facilities at full capacity due to restrictions imposed by environmental regulations, its revenues could decrease due to decreased wholesale sales and its expenses could increase due to the need to obtain energy from higher-cost sources. Any reduction of revenues or increase in expenses resulting from the risks described above could decrease PacifiCorp’s cash flows and weaken its financial position.

Furthermore, PacifiCorp’s current and future insurance coverage may not be sufficient to replace lost revenues or cover repair and replacement costs, especially in light of recent catastrophic events affecting the insurance markets that make it more difficult or costly to obtain certain types of insurance.

***Acts of sabotage and terrorism aimed at PacifiCorp’s facilities, the facilities of its fuel suppliers or customers, or at regional transmission facilities could adversely affect PacifiCorp’s business.***

Since the September 11, 2001 terrorist attacks, the United States government has issued warnings that energy assets, specifically the nation’s pipeline and electric utility infrastructure, may be the future targets of terrorist organizations. These developments have subjected PacifiCorp’s operations to increased risks. Damage to PacifiCorp’s assets, the assets of PacifiCorp’s fuel suppliers or customers, or to regional transmission facilities inflicted by terrorist groups or saboteurs could

result in a significant decrease in revenues and significant repair costs, force PacifiCorp to increase security measures, cause changes in the insurance markets and cause disruptions of fuel supplies, energy consumption and markets, particularly with respect to natural gas and electric energy. Any of these consequences of acts of terrorism could materially affect PacifiCorp's results of operations and cash flows. Instability in the financial markets as a result of terrorism or war could also materially adversely affect PacifiCorp's ability to raise capital.

***Recovery of costs by PacifiCorp is subject to regulatory review and approval, and the inability to recover costs may adversely affect PacifiCorp's revenues and cash flows.***

PacifiCorp is subject to the jurisdiction of federal and state regulatory authorities. The FERC establishes tariffs under which PacifiCorp provides transmission service to the wholesale market and the retail market (in states allowing retail competition). The FERC also establishes both cost-based and market-based tariffs under which PacifiCorp sells electricity at wholesale and has licensing authority over most of PacifiCorp's hydroelectric generation facilities. In addition, the utility regulatory commissions in each state served by PacifiCorp independently determine the rates that PacifiCorp may charge its retail customers in those states.

Each state's rate-setting process is based upon the state utility commission's acceptance of an allocated share of PacifiCorp's total utility costs for its entire retail service territory. When different states adopt different methods to address this cost allocation issue, some costs may not be incorporated into rates in any state. Rate-making is also generally done on the basis of estimates of normalized costs, so if in a specific year realized costs are higher than normal, rates will not be sufficient to cover those costs. Each state utility commission generally sets rates based on a test year established according to that commission's policies. Certain states use a future test year or allow for escalation of historical costs. In the states in which PacifiCorp operates that use a historical test year, rate adjustments could lag cost increases, or decreases, by up to two years. This regulatory lag causes PacifiCorp to incur costs, including significant new investments, for which recovery through rates is delayed. In addition, each state commission decides what percentage return a utility will be permitted to earn on its equity. Each commission also decides what level of expense and investment is necessary, reasonable and prudent in providing service and may disallow and deny recovery in rates for any costs that do not meet this standard. For these reasons, as well as others (such as recently enacted legislation and the outcome of the recent rate order in Oregon limiting or denying the ability of a utility to recover tax expenses in rates), the rates authorized by the state regulators may not be sufficient to cover costs incurred to provide electrical services in any given period.

***PacifiCorp is subject to energy regulation, legislation and political risks, and changes in regulations and rates or legislative developments may adversely affect its business, financial condition, results of operations and cash flows.***

PacifiCorp is subject to comprehensive governmental regulation, including regulation by various federal, state and local regulatory agencies, which significantly influences PacifiCorp's operating environment, the prices it is allowed to charge customers, its capital structure, its costs and its ability to recover costs from customers. These regulatory agencies include the FERC, the EPA, and the public utility commissions in Utah, Oregon, Wyoming, Washington, Idaho and California.

PacifiCorp also conducts its businesses in conformance with a multitude of federal, state and local laws, which are subject to significant changes at any time. Changes in regulations or the imposition of additional regulations by any of these regulatory entities, as well as new legislation, could have a material adverse impact on PacifiCorp's results of operations. For example, such changes could result in increased retail competition in PacifiCorp's service territory, changes to the hydroelectric relicensing process under the Federal Power Act, encouragement of investments in renewable or lower-emission generation, the acquisition by a municipality or other quasi-governmental body of PacifiCorp's distribution facilities (by negotiation, legislation or condemnation or by a vote in favor of a Public Utility District under Oregon law), or a negative impact on PacifiCorp's current cost recovery arrangements. As another example, PacifiCorp could be adversely affected by Senate Bill 408, which was recently enacted in Oregon. That legislation, and the outcome of a recent rate case, which is currently under formal reconsideration, resulted in a reduction by the OPUC in the rates that PacifiCorp is currently permitted to charge to its Oregon customers, and in the future may limit the ability of PacifiCorp and other public utilities to recover future federal and state income tax expenses in Oregon retail rates. Unless Senate Bill 408 is amended, modified or repealed, or the pending rehearing of the rate case is resolved, in a manner satisfactory to PacifiCorp, such legislation and rules could have a material adverse effect upon PacifiCorp's results of operations and cash flows.

Several of PacifiCorp's hydroelectric projects are in some stage of the FERC relicensing process under the Federal Power Act, as several of PacifiCorp's long-term operating licenses have expired or will expire in the next few years. The relicensing process is a political and public regulatory process that involves sensitive resource issues and uncertainties. PacifiCorp cannot predict with certainty the requirements that may be imposed during the relicensing process, the economic impact of those requirements, whether new licenses will ultimately be issued or whether PacifiCorp will be willing to meet the relicensing requirements to continue operating its hydroelectric projects. Loss of hydroelectric resources or additional commitments arising from the relicensing process could increase PacifiCorp's operating costs or result in large capital expenditures that reduce earnings and cash flows.

In August 2005, the Energy Policy Act of 2005 was signed into law. That law potentially impacts many segments of the energy industry. The law directed the FERC to issue new regulations and regulatory decisions in areas such as electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority. While the FERC has now issued rules and decisions on multiple aspects of the Energy Policy Act of 2005, the full impact of those decisions remains uncertain. As a result of past events affecting electric reliability, the Energy Policy Act of 2005 requires federal agencies, working together with non-governmental organizations charged with electric reliability responsibilities, to adopt and implement measures designed to ensure the reliability of electric transmission and distribution systems. The implementation of such measures could result in the imposition of more comprehensive or stringent requirements on PacifiCorp or other industry participants, which would result in increased compliance costs and could have a material adverse effect on PacifiCorp's business, financial position, results of operations and cash flows.

***PacifiCorp is subject to market risk, counterparty performance risk and other risks associated with wholesale energy markets.***

In general, market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas and coal, which is compounded by energy volume changes affecting the availability of and/or demand for electricity and fuel. PacifiCorp purchases electricity and fuel in the open market or pursuant to short-term or variable-priced contracts as part of its normal operating business. If market prices rise, especially in a time when PacifiCorp requires larger than expected volumes that must be purchased at market or short-term prices, PacifiCorp may have significantly greater costs than anticipated. In addition, it may not be able to timely recover all, if any, of those increased costs through rate-making, due to retroactive rate-making prohibitions, unless deferred accounting or power cost recovery mechanisms have been previously authorized. Likewise, if electricity market prices drop in a period when PacifiCorp is a net seller of electricity in the wholesale market, PacifiCorp will earn less revenue, possibly to the extent of not recovering the cost of generating the electricity. Wholesale electricity prices are influenced primarily by factors throughout the western United States relating to supply and demand. Those factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Energy volume changes are caused by unanticipated changes in generation availability and/or changes in customer demand for power due to the weather, the economy and customer behavior. Although PacifiCorp plans for resources to meet its current and expected power delivery obligations, its power costs may be adversely impacted by market risk.

PacifiCorp is also exposed to risk related to performance of contractual obligations by its wholesale suppliers and customers. PacifiCorp relies on suppliers to deliver natural gas, coal and electricity in accordance with short- and long-term contracts. Failure or delay by suppliers to provide natural gas, coal or electricity pursuant to existing contracts could disrupt PacifiCorp's ability to deliver electricity and require it to incur additional expenses to meet the needs of its customers. In addition, as these contractual agreements end, PacifiCorp may not be able to continue to purchase natural gas, coal or electricity on terms equivalent to the terms of current contractual agreements. PacifiCorp relies on wholesale customers to take delivery of the energy they have committed to purchase and to pay for the energy on a timely basis. Failure of customers to take delivery may require PacifiCorp to find other customers to take the energy at lower prices than the original customers committed to pay. At certain times of year, prices paid by PacifiCorp for energy needed to satisfy its customers' demand for power may exceed the amounts PacifiCorp receives through retail rates from these customers. If the strategy PacifiCorp uses to economically hedge the exposure to these risks is ineffective, it could incur significant losses.

***Weather conditions can adversely affect PacifiCorp's operating results.***

Although PacifiCorp's service territory has historically experienced complementary seasonal customer power demand patterns as a result of the geographically diverse area of its operations, weather conditions can significantly affect operating results. For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. For example, in periods of unusually hot summer weather, residential customers tend to use significantly greater amounts of electricity to run air conditioners, which may substantially increase summer peak power demand. Changes in weather conditions and other natural events also impact customer behavior and power demand. Additionally, a portion of PacifiCorp's supply of electricity comes from hydroelectric projects that are dependent upon rainfall and snowpack. During or following periods of low rainfall or snowpack, PacifiCorp may obtain substantially less electricity from hydroelectric projects and must purchase greater amounts of electricity from the wholesale market or from other sources at market prices. Accordingly, variations in weather conditions can adversely affect PacifiCorp's results of operations through lower revenues and/or increased energy costs.

***PacifiCorp is subject to environmental, health, safety and other laws and regulations that may adversely impact its business.***

PacifiCorp is subject to a number of environmental, health, safety and other laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, endangered species, wastewater discharges, solid wastes, hazardous substances and safety matters. PacifiCorp may incur substantial costs and liabilities in connection with its operations as a result of these laws and regulations. In particular, the cost of future compliance with federal, state and local clean air laws, such as those that relate to addressing regional haze issues and those that require certain generators, including some of PacifiCorp's electric generating facilities, to limit emissions of nitrogen oxide, sulfur dioxide, carbon dioxide, mercury and other potential pollutants or emissions, may require PacifiCorp to make significant capital expenditures that may not be recoverable through future rates. In addition, these costs and liabilities may include those relating to claims for damages to property and persons resulting from PacifiCorp's operations. Regulatory changes, including new interpretations of existing laws and regulations, imposing more comprehensive or stringent requirements on PacifiCorp, to the extent such changes would result in increased compliance costs or additional operating restrictions, could have a material adverse effect on PacifiCorp's business, financial position, results of operations and cash flows.

Furthermore, regulatory compliance for existing facilities and the construction of new facilities is a costly and time-consuming process, and intricate and rapidly changing environmental regulations may require major expenditures for permitting and create the risk of expensive delays or material impairment of value if projects cannot function as planned due to changing regulatory requirements or local opposition.

In addition to operational standards, environmental laws also impose obligations to clean up or remediate contaminated properties or to pay for the cost of such remediation, often upon parties that did not actually cause the contamination. Accordingly, PacifiCorp may become liable, either contractually or by operation of law, for remediation costs even if the contaminated property is not presently owned or operated by it, or if the contamination was caused by third parties during or prior to its ownership or operation of the property. Given the nature of the past industrial operations conducted by PacifiCorp and others at its properties, all potential instances of soil or groundwater contamination may not have been identified, even for those properties where an environmental site assessment or other investigation has been conducted. Although PacifiCorp has accrued reserves for its known remediation liabilities, future events, such as changes in existing laws or policies or their enforcement, or the discovery of currently unknown contamination, may give rise to additional remediation liabilities which may be material. Any failure to recover increased environmental, health or safety costs incurred by PacifiCorp may have a material adverse effect on its business, financial position, results of operations and cash flows.

***Poor performance of pension plan investments and other factors impacting pension plan costs could unfavorably impact PacifiCorp's liquidity and results of operations.***

PacifiCorp's costs of providing non-contributory defined benefit pension plans depend upon a number of factors, including the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and PacifiCorp's required or voluntary contributions made to the plans. While PacifiCorp complies with the minimum funding requirements under federal law, as of March 31, 2006 its projected benefit obligations, which include the impact of expected future compensation increases, exceeded the value of plan assets by approximately \$513.6 million, including contributions made between the December 31, 2005 measurement date and

March 31, 2006. Without sustained growth in the pension investments over time to increase the value of its pension plan assets, and depending upon the other factors described above, PacifiCorp could be required to fund its pension plans with significant amounts of cash. Such cash funding obligations, as well as the impact of the other factors described above, could have a material impact on PacifiCorp's liquidity by reducing its cash flows and could negatively affect its results of operations.

***A downgrade in PacifiCorp's credit ratings could negatively affect its ability to access capital and its ability to economically hedge in wholesale markets.***

Changes in PacifiCorp's financial performance, capital structure, the regulatory environment in which it operates and other factors expose it to the risk of a credit ratings downgrade by Standard and Poor's or Moody's Investor Services, the principal ratings agencies that evaluate PacifiCorp's creditworthiness and that of its debt securities and preferred stock. Although PacifiCorp has no rating-downgrade triggers that would accelerate the maturity dates of its outstanding debt. A downgrade in its credit ratings could directly increase the interest rates and commitment fees on its revolving credit agreement. A ratings downgrade also may reduce the accessibility and increase the cost of PacifiCorp's commercial paper program, its principal source of short-term borrowing, and may result in the requirement that PacifiCorp post collateral under certain of its power purchase and other agreements. In addition, a credit ratings downgrade could allow counterparties in the wholesale electric, wholesale natural gas and energy derivatives markets to require PacifiCorp to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other mutually agreeable security. These consequences of a credit ratings downgrade could increase PacifiCorp's borrowing and operating costs.

***PacifiCorp has a substantial amount of debt, which could adversely affect its ability to obtain future financing and limit its expenditures.***

As of March 31, 2006, PacifiCorp had \$4.1 billion in total debt securities outstanding. Its principal financing agreements contain restrictive covenants that limit its ability to borrow funds, and any issuance of debt securities requires prior authorization from multiple state regulatory commissions. PacifiCorp expects that it will need to supplement cash generated from operations and availability under committed credit facilities with new issuances of long-term debt. However, if market conditions are not favorable for the issuance of long-term debt, or if an issuance of long-term debt would exceed contractual or regulatory limits, PacifiCorp may postpone planned capital expenditures, or take other actions, to the extent those expenditures are not fully covered by cash from operations or equity contributions from MEHC and not available under committed credit facilities.

***MEHC may exercise its significant influence over PacifiCorp in a manner that would benefit MEHC to the detriment of PacifiCorp's creditors and preferred stockholders.***

MEHC, through its subsidiary, owns all of PacifiCorp's common stock and therefore has significant influence over its business and any matters submitted for shareholder approval. In circumstances involving a conflict of interest between MEHC and PacifiCorp's creditors and preferred stockholders, MEHC could exercise its influence in a manner that would benefit MEHC to the detriment of PacifiCorp's creditors and preferred stockholders.

## **ITEM 1B. UNRESOLVED STAFF COMMENTS**

No information is required to be reported pursuant to this item.

## **ITEM 2. PROPERTIES**

PacifiCorp owns its principal properties in fee (except as indicated below), subject to defects and encumbrances that do not interfere materially with their use. Substantially all of PacifiCorp's electric utility properties are subject to the lien of PacifiCorp's Mortgage and Deed of Trust. See "Item 15. Exhibits, Financial Statement Schedules - Exhibit 4.1." PacifiCorp considers all of its properties to be well maintained, in good operating condition, and suitable for their intended purposes.

### **Headquarters/Offices**

PacifiCorp's corporate offices consist of approximately 900,000 square feet of owned and leased office space located in several buildings in Portland, Oregon, and Salt Lake City, Utah. PacifiCorp's corporate headquarters are in Portland, but there are several executives and departments located in Salt Lake City. In addition to the corporate headquarters, PacifiCorp owns and leases approximately 1.2 million square feet of field office and warehouse space in various other locations in Utah, Oregon, Wyoming, Washington, Idaho and California. The field location square footage does not include offices located at PacifiCorp's generating plants.

### **Generation**

PacifiCorp owns, or has an interest in, various hydroelectric, thermal and wind generating plants. A generator's nameplate rating is its full-load capacity (in megawatts) under normal operating conditions as defined by the manufacturer. The net capability is the maximum level a generator can operate at under specified conditions. The following table summarizes PacifiCorp's existing generating plants:

	Location	Energy Source	Unit Installation Date(s)	Nameplate Rating (MW)	Plant Net Capability (MW)
<b>HYDROELECTRIC PLANTS (a)</b>					
Swift No. 1 (b)	Cougar, WA	Lewis River	1958	240.0	264.0
Merwin	Ariel, WA	Lewis River	1931-1958	136.0	144.0
Yale	Amboy, WA	Lewis River	1953	134.0	165.0
Five North Umpqua Plants	Toketee Falls, OR	N. Umpqua River	1950-1956	136.5	138.5
John C. Boyle	Keno, OR	Klamath River	1958	90.4	94.0
Copco Nos. 1 and 2 Plants	Hornbrook, CA	Klamath River	1918-1925	47.0	54.5
Clearwater Nos. 1 and 2 Plants	Toketee Falls, OR	Clearwater River	1953	41.0	41.0
Grace	Grace, ID	Bear River	1908-1923	33.0	33.0
Prospect No. 2	Prospect, OR	Rogue River	1928	32.0	36.0
Cutler	Collingston, UT	Bear River	1927	30.0	29.1
Oneida	Preston, ID	Bear River	1915-1920	30.0	28.0
Iron Gate	Hornbrook, CA	Klamath River	1962	18.0	20.0
Soda	Soda Springs, ID	Bear River	1924	14.0	14.0
Fish Creek	Toketee Falls, OR	Fish Creek	1952	11.0	12.0
31 Minor Hydroelectric Plants (c)	Various	Various	1895-1990	90.7 *	86.3 *
Subtotal (51 Hydroelectric Plants)				<u>1,083.6</u>	<u>1,159.4</u>
<b>THERMAL PLANTS</b>					
Jim Bridger	Rock Springs, WY	Coal-Fired	1974-1979	1,541.1 *	1,413.4 *
Huntington	Huntington, UT	Coal-Fired	1974-1977	996.0	895.0
Dave Johnston	Glenrock, WY	Coal-Fired	1959-1972	816.8	762.0
Naughton	Kemmerer, WY	Coal-Fired	1963-1971	707.2	700.0
Hunter Nos. 1 and 2	Castle Dale, UT	Coal-Fired	1978-1980	727.9 *	662.0 *
Hunter No. 3	Castle Dale, UT	Coal-Fired	1983	495.6	460.0
Cholla No. 4	Joseph City, AZ	Coal-Fired	1981	414.0	380.0
Wyodak	Gillette, WY	Coal-Fired	1978	289.7 *	268.0 *
Carbon	Castle Gate, UT	Coal-Fired	1954-1957	188.6	172.0
Craig Nos. 1 and 2	Craig, CO	Coal-Fired	1979-1980	172.1 *	165.0 *
Colstrip Nos. 3 and 4	Colstrip, MT	Coal-Fired	1984-1986	155.6 *	149.0 *
Hayden Nos. 1 and 2	Hayden, CO	Coal-Fired	1965-1976	81.3 *	78.0 *
Currant Creek	Mona, UT	Natural Gas-Fired	2005-2006	566.9	523.0
Hermiston	Hermiston, OR	Natural Gas-Fired	1996	279.6 *	237.0 *
Gadsby Steam	Salt Lake City, UT	Natural Gas-Fired	1951-1952	257.6	235.0
Gadsby Peak	Salt Lake City, UT	Natural Gas-Fired	2002	141.0	120.0
Little Mountain	Ogden, UT	Natural Gas-Fired	1972	16.0	14.0
Camas Co-Gen	Camas, WA	Black Liquor	1996	61.5	22.0
Blundell (d)	Milford, UT	Geothermal	1984	26.1	23.0
Subtotal (17 Thermal Electric Plants)				<u>7,934.6</u>	<u>7,278.4</u>
<b>WIND PLANT</b>					
Foot Creek	Arlington, WY	Wind Turbines	1998	32.6 *	32.6 *
Subtotal (1 Other Plant)				<u>32.6</u>	<u>32.6</u>
Total Generating Plants (69)				<u>9,050.8</u>	<u>8,470.4</u>

\* Jointly owned plants; amount shown represents PacifiCorp's share only.

(a) Hydroelectric project locations are stated by locality and river watershed.

(b) On April 21, 2002, the Cowlitz County Public Utility District-owned Swift No. 2 power canal failed, impacting the operations of the PacifiCorp-owned 240.0 MW Swift No. 1 hydroelectric facility. In June 2004, PacifiCorp and Cowlitz County Public Utility District, through an amendment to an existing power purchase agreement, agreed to a

mechanism for settling all claims and terms of rebuilding. Reconstruction of the canal is nearing completion and the project began operating on an interim basis in the three months ended March 31, 2006.

- (c) PacifiCorp has negotiated settlement agreements with resource agencies and other interested parties to decommission the American Fork, Condit, Cove Development and Powerdale hydroelectric plants, which have a combined net capability of 16.6 MW. These settlement agreements have been filed with the FERC and are pending further regulatory action.
- (d) As a result of the settlement agreement between MEHC, the Utah Committee of Consumer Services ("CCS"), a state utility consumer advocate, and Utah Industrial Energy Consumers, MEHC contributed to PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Therefore, Intermountain Geothermal Company became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC.

In May 2002, PacifiCorp entered into a 15-year operating lease for an electric generation facility with West Valley Leasing Company, LLC, an indirect subsidiary of ScottishPower. The Utah facility consists of five generation units with an aggregate nameplate rating of 217.0 MW and a net plant capability of 202.0 MW. PacifiCorp, at its sole option, may terminate the lease, or purchase the facility, if written notice is provided to West Valley on or before December 1, 2006. If the termination option is exercised, the lease would end in May 2008.

### **Transmission and Distribution**

PacifiCorp's generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through the transmission lines of other transmission owners. Substantially all of PacifiCorp's generating plants and reservoirs are managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of PacifiCorp's transmission and distribution systems are located:

- On property owned or leased by PacifiCorp;
- Under or over streets, alleys, highways and other public places, the public domain and national forests and state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the record holder of title; or
- Under or over Native American reservations under grant of easement by the Secretary of Interior or lease by Native American tribes.

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

At March 31, 2006, PacifiCorp owned, or participated in, an electric transmission and distribution system consisting of:

Nominal Voltage (In kilovolts)	Miles
Transmission Lines	
500	720
345	1,900
230	3,360
161	280
138	2,050
115	1,540
69	2,970
57	110
46	2,650
	15,580
Distribution Lines	
Less than 46	59,510
Total	75,090

At March 31, 2006, PacifiCorp owned 908 substations.

### Mining

PacifiCorp believes that the respective coal reserves available to the Craig, Huntington, Hunter and Jim Bridger Plants, together with coal available under both long-term and short-term contracts with external suppliers, will be substantially sufficient to provide these plants with fuel that meets the Clean Air Act standards for their current economically useful lives. Blending of PacifiCorp-owned and contracted coal, together with electricity plant technologies for controlling sulfur and other emissions, are utilized to meet the applicable standards. PacifiCorp-owned plants held sufficient sulfur dioxide emission allowances to comply with the EPA Title IV requirements during the compliance year. The sulfur content of the coal reserves ranges from 0.30% to 0.94%, and the British Thermal Units value per pound of the reserves ranges from 8,600 to 12,400.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves at March 31, 2006, based on PacifiCorp's most recent engineering studies, were as follows:

Location	Plant Served	Mining Method	Recoverable Tons (in Millions)
Craig, CO	Craig	Surface	48.0 (a)
Huntington & Castle Dale, UT	Huntington and Hunter	Underground	61.1 (b)
Rock Springs, WY	Jim Bridger	Surface/Underground	139.2 (c)

- (a) These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis, in which PacifiCorp has an ownership interest of 21.4%.
- (b) These coal reserves are leased by PacifiCorp and mined by a wholly owned subsidiary of PacifiCorp.
- (c) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. ("PMI") and a subsidiary of Idaho Power Company. PMI, a subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The Bridger mine is in the process of conversion from surface operation to primarily underground operation, while currently continuing production at its surface operations.

Recoverability by surface mining methods typically ranges from 90.0% to 95.0%. Recoverability by underground mining techniques ranges from 50.0% to 70.0%. Most of PacifiCorp's coal reserves are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have

multi-year terms that may be renewed or extended and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities. See "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs."

### ITEM 3. LEGAL PROCEEDINGS

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in state district court in Salt Lake City, Utah by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon, LLC (collectively, "USA Power"), against Utah attorney Jody L. Williams and the law firm Holme, Roberts & Owen, LLP, who represent PacifiCorp on various matters from time to time. USA Power is the developer of a planned generation project in Mona, Utah called Spring Canyon, which PacifiCorp, as part of its resource procurement process, at one time considered as an alternative to the Currant Creek Power Plant. USA Power's complaint alleges that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accuses PacifiCorp of breach of contract and related claims. USA Power seeks \$250.0 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. PacifiCorp believes it has a number of defenses and intends to vigorously oppose any claim of liability for the matters alleged by USA Power. Furthermore, PacifiCorp expects that the outcome of this proceeding will not have a material impact on its consolidated financial position, results of operations or liquidity.

In October 2005, CCS filed a request for agency action with the UPSC. The request sought an order requiring PacifiCorp to return to Utah ratepayers certain monies collected in Utah rates for taxes, which the CCS alleges were improperly retained by PacifiCorp's parent company, PHI. The CCS has publicly announced it is seeking a refund of at least \$50.0 million to Utah ratepayers. Following PacifiCorp's sale to MEHC in March 2006, the CCS, MEHC and intervening party Utah Industrial Energy Consumers filed with the UPSC an agreement settling the claims made by the CCS. In exchange for dismissal of the claims, MEHC agreed to contribute to PacifiCorp, at no cost, MEHC's 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. The settlement agreement has been approved by the UPSC, which dismissed the CCS request.

In May 2004, PacifiCorp was served with a complaint filed in the United States District Court for the District of Oregon by the Klamath Tribes of Oregon, individual Klamath Tribal members and the Klamath Claims Committee. The complaint generally alleges that PacifiCorp and its predecessors affected the Klamath Tribes' federal treaty rights to fish for salmon in the headwaters of the Klamath River in southern Oregon by building dams that blocked the passage of salmon upstream to the headwaters beginning in 1911. In September 2004, the Klamath Tribes filed their first amended complaint adding claims of damage to their treaty rights to fish for sucker and steelhead in the headwaters of the Klamath River. The complaint seeks in excess of \$1.0 billion in compensatory and punitive damages. In July 2005, the District Court dismissed the case and in September 2005 denied the Klamath Tribes' request to reconsider the dismissal. In October 2005, the Klamath Tribes appealed the District Court's decision to the Ninth Circuit Court of Appeals and briefing was completed in March 2006. Any final order will be subject to appeal. PacifiCorp believes the outcome of this proceeding will not have a material impact on its consolidated financial position, results of operations or cash flow.

In April 2004, PacifiCorp filed a complaint with the federal district court in Wyoming challenging the WPSC decision made in March 2003 to deny recovery of the Hunter No. 1 replacement power costs and certain deferred excess net power costs. The complaint was filed on the grounds that the decision violates federal law by denying PacifiCorp recovery in retail rates of its wholesale electricity and transmission costs incurred to serve Wyoming customers. In February 2006, PacifiCorp and certain parties intervening in its then-pending Wyoming general rate case reached a settlement of the terms of PacifiCorp's general rate case request. PacifiCorp also agreed to dismiss its federal lawsuit challenging the WPSC decision. The case was dismissed in May 2006.

In December 2004, a group of Utah customers filed a petition with the UPSC on behalf of themselves and other similarly situated customers seeking monetary compensation from PacifiCorp as a result of a severe winter storm in December 2003. This petition was substantially similar to an April 2004 petition that the UPSC resolved by consolidating customer requests with an ongoing regulatory winter storm inquiry. In May 2006, PacifiCorp reached a stipulation with the petitioners that resolved all claims in consideration of system maintenance and vegetation management commitments and additional credits for customers. The stipulation was approved by the UPSC on May 22, 2006.

#### **ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS**

No information is required to be reported pursuant to this item.

### **PART II**

#### **ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES**

PacifiCorp is an indirect subsidiary of MEHC, which owns all shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock. Dividend information required by this item is included in "Item 8. Financial Statements and Supplementary Data – Quarterly Financial Data."

The state regulatory orders that authorized the acquisition by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

In addition, PacifiCorp is restricted from making any distributions to PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of March 31, 2006, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp does not presently anticipate that it will declare dividends on common stock during the 12 months ending March 31, 2007.

PacifiCorp is also subject to maximum debt-to-total capitalization ratios under various debt agreements. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources."

## ITEM 6. SELECTED FINANCIAL DATA (Unaudited)

(Millions of dollars, except per share and employee amounts)

	Years Ended March 31,				
	2006	2005	2004	2003	2002
<b>Revenues:</b>					
Electric Operations	\$ 3,896.7	\$ 3,048.8	\$ 3,194.5	\$ 3,082.4	\$ 3,341.1
Australian Operations	-	-	-	-	-
Other Operations (a)	-	-	-	-	12.6
<b>Total</b>	<b>\$ 3,896.7</b>	<b>\$ 3,048.8</b>	<b>\$ 3,194.5</b>	<b>\$ 3,082.4</b>	<b>\$ 3,353.7</b>
<b>Income (loss) from operations:</b>					
Electric Operations	\$ 792.0	\$ 656.4	\$ 617.9	\$ 488.9	\$ 598.6
Australian Operations	-	-	-	-	27.4
Other Operations (a)	-	-	-	-	15.0
<b>Total</b>	<b>\$ 792.0</b>	<b>\$ 656.4</b>	<b>\$ 617.9</b>	<b>\$ 488.9</b>	<b>\$ 641.0</b>
<b>Net income</b>	<b>\$ 360.7</b>	<b>\$ 251.7</b>	<b>\$ 248.1</b>	<b>\$ 140.1</b>	<b>\$ 327.3</b>
<b>Earnings on common stock:</b>					
<b>Continuing operations</b>					
Electric Operations	\$ 358.6	\$ 249.6	\$ 245.7	\$ 134.7	\$ 232.8
Australian Operations	-	-	-	-	27.4
Other Operations (a)	-	-	-	-	20.5
<b>Total</b>	<b>358.6</b>	<b>249.6</b>	<b>245.7</b>	<b>134.7</b>	<b>280.7</b>
Discontinued operations (b)	-	-	-	-	146.7
Cumulative effect of accounting change (c) (d) (e)	-	-	(0.9)	(1.9)	(112.8)
<b>Total earnings on common stock</b>	<b>\$ 358.6</b>	<b>\$ 249.6</b>	<b>\$ 244.8</b>	<b>\$ 132.8</b>	<b>\$ 314.6</b>
<b>Common dividends declared per share</b>	<b>\$ 0.53</b>	<b>\$ 0.62</b>	<b>\$ 0.51</b>	<b>\$ -</b>	<b>\$ 0.81</b>
<b>Common dividends paid per share</b>	<b>\$ 0.53</b>	<b>\$ 0.62</b>	<b>\$ 0.51</b>	<b>\$ -</b>	<b>\$ 1.00</b>
<b>At March 31,</b>					
	2006	2005	2004	2003	2002
<b>Capitalization:</b>					
Short-term debt	\$ 184.4	\$ 468.8	\$ 124.9	\$ 25.0	\$ 177.5
Long-term debt, including current maturities	3,937.9	3,898.9	3,760.2	3,554.3	3,698.3
Preferred Securities of Trusts	-	-	-	341.8	341.5
Preferred stock subject to mandatory redemption	45.0	52.5	60.0	66.7	74.2
Preferred stock	41.3	41.3	41.3	41.3	41.3
Common equity	4,010.5	3,335.8	3,278.7	3,194.4	2,891.9
<b>Total Capitalization</b>	<b>\$ 8,219.1</b>	<b>\$ 7,797.3</b>	<b>\$ 7,265.1</b>	<b>\$ 7,223.5</b>	<b>\$ 7,224.7</b>
<b>Total assets</b>	<b>\$ 12,731.3</b>	<b>\$ 12,520.9</b>	<b>\$ 11,677.1</b>	<b>\$ 11,695.8</b>	<b>\$ 10,234.9</b>
<b>Total employees</b>	<b>6,750</b>	<b>6,654</b>	<b>6,507</b>	<b>6,140</b>	<b>6,287</b>

- (a) Other Operations includes the activities of PacifiCorp Financial Services, Inc. and PacifiCorp Group Holdings Company, until their transfer in February 2002 to PacifiCorp's former parent company, PHI.
- (b) The year ended March 31, 2002 includes the collection of a contingent note receivable relating to the discontinued operations of a former mining and resource development business, NERCO, Inc.
- (c) The year ended March 31, 2004 reflects the effect of implementation of Statement of Financial Accounting Standards ("SFAS") No. 143, *Asset Retirement Obligations* ("SFAS No. 143").
- (d) The year ended March 31, 2003 reflects the effect of the implementation of the Derivatives Implementation Group (the

“DIG”) Revised Issue C15, *Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity* (“Issue C15”), and Issue C16, *Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract* (“Issue C16”).

- (e) The year ended March 31, 2002, reflects the effect of the implementation of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, (“SFAS No. 133”). Upon receiving regulatory approval, PacifiCorp has subsequently recorded the effects of unrealized gains or losses on certain long-term contracts as regulatory assets and liabilities.

## **ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

### **OVERVIEW**

The Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements.

PacifiCorp is a regulated electricity company serving approximately 1.6 million retail customers in service territories aggregating approximately 136,000 square miles in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The regulatory commissions in each state approve rates for retail electric sales within their respective states. PacifiCorp also sells electricity on the wholesale market to public and private utilities, energy marketing companies and to incorporated municipalities. Wholesale activities are regulated by the FERC. PacifiCorp owns, or has interests in, 69 thermal, hydroelectric and wind generating plants, with an aggregate nameplate rating of 9,050.8 MW and plant net capability of 8,470.4 MW. The FERC and the six state regulatory commissions also have authority over the construction and operation of PacifiCorp's electric generation facilities. PacifiCorp delivers electricity through approximately 59,510 miles of distribution lines and approximately 15,580 miles of transmission lines.

#### **Sale of PacifiCorp**

As described in "Item 1. Business – Overview – Ownership by MEHC; Sale of PacifiCorp," MEHC completed its acquisition of PacifiCorp from ScottishPower and PHI on March 21, 2006. MEHC purchased all PacifiCorp common stock for approximately \$5.1 billion in cash.

In January through March 2006, the state commissions in all six states where PacifiCorp has retail customers approved PacifiCorp's sale to MEHC. The approvals were conditioned on a number of regulatory commitments, including expected financial benefits in the form of reduced corporate overhead and financing costs, certain mid- to long-term capital and other expenditures of significant amounts and a commitment not to seek utility rate increases attributable solely to the change in ownership. The capital and other expenditures proposed by MEHC and PacifiCorp include:

- Approximately \$812.0 million in investments (generally to be made over several years following the sale and subject to subsequent regulatory review and approval) in emissions reduction technology for PacifiCorp's existing coal plants, which, when coupled with the use of reduced emissions technology for anticipated new coal-fueled generation, is expected to result in significant reductions in emissions rates of sulfur dioxide, nitrogen oxide and mercury and to avoid an increase in the carbon dioxide emissions rate;
- Approximately \$519.5 million in investments (to be made over several years following the sale and subject to subsequent regulatory review and approval) in PacifiCorp's transmission and distribution system that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization; and
- The addition of 400.0 MW of cost-effective renewable resources to PacifiCorp's generation portfolio by December 31, 2007, including 100.0 MW of cost-effective wind resources by March 21, 2007.

The commitments approved by the state commissions also include credits that will reduce retail rates generally through 2010 to the extent that PacifiCorp does not achieve identified cost reductions or demonstrate mitigation of certain risks to customers. The maximum potential value of these rate credits to customers in all six states is \$142.5 million. PacifiCorp and MEHC have made additional commitments to the state commissions that limits the dividends PacifiCorp can make to MEHC or its affiliates. As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

## Forward-Looking Statements

This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, made in this report are forward-looking. When used in this Management's Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this report, the words "will," "may," "could," "believes," "estimates," "expects," "anticipates," "forecasts," "plans," "intends," "projected," "potential" and variations of such words and similar expressions are intended to identify forward-looking statements. Forward-looking statements included in this report relate to, among other matters, the effect on PacifiCorp of the following: regulatory commitments related to PacifiCorp's sale to MEHC; recently enacted Oregon Senate Bill 408; potential adjustment of regulatory rates to cover costs; growth of retail customers and demand; the impact of new accounting standards or accounting policy changes; the outcome of litigation or regulatory proceedings; the timing of future regulatory filings; environmental laws; federal energy policy and legislation; capital expenditure levels; results from, and the timing of, the construction or repair of generating facilities; hydroelectric relicensing and decommissioning activities; electricity outages; pension and other postretirement contributions; outcome of tax proceedings; growth in customers and usage; levels of hydroelectric and thermal generation; sufficiency of PacifiCorp's available funds to meet its liquidity needs and future financing; off-balance sheet arrangements; the effect of risk management measures, including use of financial derivatives to manage and mitigate interest rate exposure; fluctuations in forward prices for electricity and natural gas; and the efficiency and effectiveness of PacifiCorp's resource and fuel procurement. Forward-looking statements reflect management's current expectations, plans or projections and are inherently uncertain. There can be no assurance the results predicted will be realized. Actual results may vary from those represented by the forecasts, and those variations may be material. The following are among the factors, in addition to those set forth under "Item 1A. Risk Factors," that could cause actual results to differ materially from the forward-looking statements:

- The outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- Changes in prices and availability (for both purchases and sales) of wholesale electricity, natural gas and other fuel sources and other changes in operating costs that could affect PacifiCorp's cost recovery;
- Changes in regulatory requirements or other legislation, including the recently enacted federal Energy Policy Act of 2005, legislation or regulatory outcomes limiting the ability of public utilities to recover income tax expense in retail rates such as Senate Bill 408, industry restructuring and deregulation initiatives;
- Industrial, commercial and residential customer growth and demographic patterns in PacifiCorp's service territories;
- Economic trends that could impact electricity usage;
- Changes in weather conditions and other natural events that could affect customer demand or electricity supply;
- A high degree of variance between actual and forecasted load and prices that could impact the hedging strategy and costs to balance electricity load and supply;
- Hydroelectric conditions, as well as natural gas and coal production and price levels, that could have a significant impact on electric capacity and cost and on PacifiCorp's ability to generate electricity;
- Performance of PacifiCorp's generation facilities, including the level of planned and unplanned outages;
- The cost, feasibility and eventual outcome of hydroelectric facility relicensing proceedings;
- Changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies that could increase operating and capital improvement costs, reduce plant output and/or delay plant construction;
- Changes resulting from MEHC ownership;
- The impact of new accounting pronouncements or changes in current accounting estimates and assumptions on financial position and results of operations;

- The impact of interest rates, investment performance and increases in health care costs on pension and post-retirement expense;
- Continued availability of funds to meet liquidity requirements;
- The impact of any required performance under off-balance sheet arrangements;
- Financial condition and creditworthiness of significant customers and suppliers;
- The impact of financial derivatives used to mitigate or manage interest rate risk and volume and price risk due to weather extremes;
- Changes in PacifiCorp's credit ratings;
- Timely and appropriate completion of PacifiCorp's resource procurement process, unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund resource projects and other factors that could affect future generation plants and infrastructure additions;
- Other risks or unforeseen events, including wars, the effects of terrorism, embargos and other catastrophic events; and
- Other business or investment considerations that may be disclosed from time to time in SEC filings or in other publicly disseminated written documents.

Any forward-looking statements issued by PacifiCorp should be considered in light of these factors. PacifiCorp does not intend to update or revise any forward-looking statements to reflect actual results, changes in assumptions or changes in other factors affecting such forward-looking statements or if PacifiCorp later becomes aware that these assumptions are not likely to be achieved.

## **Accounting Matters**

### **Critical Accounting Estimates and Related Policies**

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the results of operations and the reported amounts of assets and liabilities in the Consolidated Financial Statements. The estimates and assumptions may change as time passes and accounting guidance evolves. Management bases its estimates and assumptions on historical experience and on other various judgments that it believes are reasonable at the time of application. Changes in these estimates and assumptions could have a material impact on the Consolidated Financial Statements. If estimates and assumptions are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Critical accounting estimates, in addition to certain less significant accounting estimates, are discussed with senior members of management and PacifiCorp's Board of Directors, as appropriate, and were previously disclosed to the ScottishPower Audit Committee and from March 21, 2006 are disclosed to the MEHC Audit Committee. Those estimates that management considers critical are described below.

### **Derivatives**

On April 1, 2001, PacifiCorp adopted SFAS No. 133, as amended. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts. PacifiCorp also enters into short-term energy derivatives on a limited basis for arbitrage purposes to take advantage of opportunities arising from market inefficiencies.

SFAS No. 133 requires that derivative instruments be recorded on the balance sheet at fair value. The fair values of derivative instruments are determined using forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement of a commodity at

future dates. PacifiCorp bases its forward price curves upon market price quotations when available and uses internally developed, modeled prices when market quotations are unavailable. In general, PacifiCorp estimates the fair value of a contract by calculating the present value of the difference between the contract and the applicable

forward price curve.

Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and, therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be estimated in other ways. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve is based upon the use of a fundamentals model (cost-to-build approach), due to the limited information available. Factors used in the fundamentals model include the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of power plants in converting fuel to electricity) in the region where the purchase or sale takes place and a fundamentals forecast of expected spot prices for a commodity in a region based on modeled supply of and demand for the commodity in the region. The assumptions in these models are critical, since any changes in assumptions could have a significant impact on the fair value of the contract.

Despite the large volume of implementation guidance, SFAS No. 133 and the supplemental guidance do not provide specific guidance on all contract issues. As a result, significant judgment must be used in applying SFAS No. 133 and its interpretations.

#### **Pensions and Other Postretirement Benefits**

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees. In addition, certain bargaining unit employees participate in a joint trust plan to which PacifiCorp contributes. PacifiCorp accounts for these plans in accordance with SFAS No. 87, *Employers' Accounting for Pensions* ("SFAS No. 87"). PacifiCorp accounts for its other postretirement benefit plan in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions* ("SFAS No. 106"). The expense and benefit obligations relating to PacifiCorp's pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected returns on plan assets, compensation increases, PacifiCorp contributions and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. The effect of modifications is generally amortized over future periods. PacifiCorp believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience, market conditions and the advice of plan actuaries. However, actual results may differ from such assumptions.

The PacifiCorp Retirement Plan (the "Retirement Plan") currently has assets with a fair value that is less than the accumulated benefit obligation, primarily due to declines in the equity markets during calendar years 2000 through 2002 and lower discount rates. PacifiCorp recognized a minimum pension liability in the three months ended March 31, 2003, and continues to recognize this liability at March 31, 2006. The liability adjustment did not affect the consolidated results of operations. PacifiCorp requested and received accounting orders from the regulatory commissions in Utah, Oregon, Wyoming and Washington to classify most of this charge as a Regulatory asset instead of a charge to Other comprehensive income. This increase to Regulatory assets was adjusted as of March 31, 2006 and 2005 and will be adjusted in future periods as the difference between the fair value of the trust assets and the accumulated benefit obligation changes. PacifiCorp has determined that costs related to SFAS No. 87 for the Retirement Plan are currently recoverable in rates.

PacifiCorp's contributions to the Retirement Plan have exceeded the minimum funding requirements of the Employee Retirement Income Security Act ("ERISA"). PacifiCorp made \$63.7 million in cash contributions to the Retirement Plan during the year ended March 31, 2006, including those contributions made between the December 31, 2005 measurement date and March 31, 2006, and made \$61.6 million in cash contributions to the Retirement Plan during the year ended March 31, 2005. In April 2006, PacifiCorp contributed \$72.7 million to its Retirement Plan and expects to contribute another \$11.0 million to its pension plans in the 12 months ending March 31, 2007. PacifiCorp is funding the Retirement Plan at what it believes to be an adequate level, but it currently expects to make larger cash contributions in the future due to its underfunded pension obligation and ERISA requirements. Such cash requirements could be material to PacifiCorp's cash flows. PacifiCorp believes it has adequate access to capital resources to support these contributions. As of March 31, 2006, PacifiCorp's underfunded status of the pension plans was \$513.6 million, including contributions made between the December 31, 2005 measurement date and March 31, 2006. For further details, see "Item 8. Financial Statements – Note 17 – Employee Benefits," which are incorporated by reference into this Item 7.

PacifiCorp discounted its future pension and other postretirement plan obligations using a rate of 5.75% at March 31, 2006 and 2005. Thus, the discount rate used for PacifiCorp's expense during the 12 months ended March 31, 2006 was 5.75% and the discount rate that will be used for PacifiCorp's expense during the 12 months ending March 31, 2007 will also be 5.75%. PacifiCorp chooses a discount rate based upon high quality fixed-income investment yields. The pension and other postretirement benefit liabilities, as well as expenses, increase as the discount rate is reduced.

At March 31, 2006, PacifiCorp assumed that the pension and other postretirement assets would generate a long-term rate of return of 8.50% for the 12 months ending March 31, 2007 compared to an assumed rate of return of 8.75% for the year ended March 31, 2006. In establishing its assumption as to the expected return on assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and independent advisors' forward-looking views of the financial markets. Pension and other postretirement benefit expenses increase as the expected rate of return on Retirement Plan and other postretirement benefit plan assets decreases.

Based on the above assumptions, PacifiCorp expects to record pension expense of \$71.0 million for the 12 months ending March 31, 2007, compared to \$63.8 million for the year ended March 31, 2006.

The following table reflects the sensitivities of the March 31, 2006 disclosures and the projected pension expense for the 12 months ending March 31, 2007 associated with a change in certain actuarial assumptions by the indicated percentage:

(Millions of dollars)				
Actuarial Assumption	Change in Assumption	Impact on Projected Benefit Obligation Increase (Decrease)	Impact on Minimum Pension Liability Increase (Decrease)	Impact on Annual Pension Cost Increase (Decrease)
Expected long-term return on plan assets	(0.5) %	\$ -	\$ -	\$ 4.2
Expected long-term return on plan assets	0.5	-	-	(4.2)
Discount rate	(0.5)	89.4	77.9	8.9
Discount rate	0.5	(83.7)	(73.0)	(8.7)

PacifiCorp expects to record other postretirement benefit expense of \$36.6 million for the 12 months ending March 31, 2007, compared to \$29.9 million for the year ended March 31, 2006. PacifiCorp has determined that costs related to SFAS No. 106 for other postretirement benefits are currently recoverable in rates. PacifiCorp contributed \$29.7 million for the year ended March 31, 2006 and \$24.9 million for the year ended March 31, 2005 to the funding vehicles for its postretirement benefit plan. PacifiCorp expects to contribute \$36.6 million to its other postretirement benefit plans for the 12 months ending March 31, 2007. As of March 31, 2006, PacifiCorp's underfunded status of the other postretirement benefit plans was \$260.6 million, including contributions made between the December 31, 2005 measurement date and March 31, 2006. For further details, see "Item 8. Financial Statements – Note 17 – Employee Benefits," which are incorporated by reference into this Item 7.

In valuing its accumulated postretirement benefit obligation, PacifiCorp must make an assumption regarding future changes in health care costs. Assumed changes impact the obligation and expense as follows:

(Millions of dollars)	Impact on Accumulated Postretirement Benefit Obligation Increase (Decrease)	Impact on Annual Other Postretirement Benefit Cost Increase (Decrease)
Assumed health care cost trend rates		
One percentage point increase	\$ 43.7	\$ 6.2
One percentage point decrease	(35.5)	(5.1)

#### **Regulation**

PacifiCorp prepares its Consolidated Financial Statements in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"). SFAS No. 71 requires PacifiCorp to reflect the impact of

regulatory decisions in its Consolidated Financial Statements and requires that certain costs be deferred on the balance sheet until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities and are amortized to the Consolidated Statements of Income as rates to customers are reduced or costs previously recovered in rates are actually incurred. SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from their treatment as allowable costs for rate-making purposes. In addition, the rate action should permit recovery of the specific previously incurred cost rather than provide for expected levels of similar future costs.

PacifiCorp is subject to state and federal regulation. In the event of deregulation, PacifiCorp would seek recovery of its net regulatory assets and any additional stranded costs. If unsuccessful, the unrecoverable portion of its net regulatory assets would be written-off and PacifiCorp would evaluate the remaining assets on its balance sheet for impairment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. PacifiCorp is unable to predict the likelihood of deregulation and its future impacts.

At March 31, 2006, PacifiCorp had recorded specifically identified regulatory assets, net of regulatory liabilities, totaling \$174.3 million. In the event PacifiCorp stopped applying SFAS No. 71 at March 31, 2006, an after-tax loss of approximately \$108.2 million would be recognized.

#### **Unbilled Revenues**

Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The unbilled revenue estimate is based on three components: PacifiCorp's total electricity delivered during the month, assignment of unbilled revenues to customer type and valuation of the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type. These estimates can vary significantly from period to period depending on monthly weather patterns, customers' space heating and cooling, production levels due to economic activity or changing irrigation patterns due to precipitation conditions.

Differences between estimated unbilled revenue and the subsequently billed revenue would most likely occur due to the variation in assignments of customer usage by revenue class and jurisdiction or variations from estimates of line losses due to changes related to line capacity utilization and weather conditions. At March 31, 2006, the amount accrued for unbilled revenues was \$148.2 million.

#### **Contingencies**

PacifiCorp follows SFAS No. 5, *Accounting for Contingencies* ("SFAS No. 5"), to determine accounting and disclosure requirements for contingencies. According to SFAS No. 5, an estimated loss from a contingency shall be charged to income if (i) it is probable that an asset has been impaired or a liability has been incurred at the date of the financial statements, and (ii) the amount of the loss can be reasonably estimated. Disclosure in the notes to the financial statements is required for loss contingencies not meeting both of these conditions if there is a reasonable possibility that a loss may have been incurred. Gain contingencies are not recorded until realized.

PacifiCorp operates in a highly regulated environment. Governmental bodies such as the FERC, state regulatory commissions, the SEC, Internal Revenue Service, Department of Labor, the EPA and others have authority over various aspects of PacifiCorp's business operations and public reporting. Reserves are established when required based upon management's best judgment. Appropriate disclosures are made regarding litigation, tax matters, environmental issues, assessments and creditworthiness of customers or counterparties, among others. The evaluation of these contingencies is performed by various specialists inside and outside of PacifiCorp. Accounting for contingencies requires significant judgment by management regarding the estimated probabilities and ranges of exposure to potential loss. Management's assessment of PacifiCorp's exposure to contingencies could change as new developments occur or more information becomes available. The outcome of the contingencies could vary significantly and could materially impact PacifiCorp's consolidated financial position, results of operations and cash flows. Management has used its best judgment in applying SFAS No. 5 to these matters.

## **New Accounting Standards**

For new accounting standards, see “Item 8. Financial Statements – Note 1 – Summary of Significant Accounting Policies,” which are incorporated by reference into this Item 7.

## **RESULTS OF OPERATIONS**

### **Overview**

PacifiCorp’s net income was \$360.7 million for the year ended March 31, 2006 compared to \$251.7 million for the year ended March 31, 2005. Significant factors affecting results for the year ended March 31, 2006 included higher retail prices approved by regulators, customer growth and a net increase in customer usage, as well as increased generation output, partially offset by higher operations and maintenance expense, including employee-related expenses, and the impact of increased fuel prices. The increase in net income was also significantly affected by a \$78.4 million increase in net unrealized gains on wholesale sales, wholesale purchase and fuel contracts primarily due to movements in forward prices.

Retail energy sales volumes grew by 2.4% in the year ended March 31, 2006 compared to the year ended March 31, 2005. PacifiCorp’s number of retail customers has been increasing by approximately 2.0% annually over the past four years. This trend is expected to continue for the foreseeable future. Increased customer usage, which also contributed to the higher volumes, is generally affected by economic and weather conditions, consumer trends and energy savings programs.

In recent years, PacifiCorp has filed general rate cases in all six states where it has retail customers, with the objective of keeping customer rates closely aligned to ongoing operating costs and to recover costs of capital investments. PacifiCorp may make additional general rate case filings in certain states over the coming year. PacifiCorp’s regulatory program has also included various other filings such as proposed power cost adjustment mechanisms. See “Item 1. Business – Regulation” for developments regarding state regulatory issues and pending rate case filings.

PacifiCorp relies on electricity generated by its thermal facilities to meet a substantial portion of its customer load. PacifiCorp’s maintenance and overhaul programs are utilized to facilitate reliable generation availability at its thermal facilities through planned outages, but PacifiCorp still may experience unplanned outages. During these outage periods, other owned generation or wholesale market purchases are utilized to balance system requirements. PacifiCorp’s hydroelectric facilities are utilized as lower-cost sources of electricity generation but are dependent upon precipitation, temperatures and other variables. Wholesale energy sales and purchase contracts are utilized to balance PacifiCorp’s physical excess or shortage of net electricity and are impacted by the movements in the market prices of both natural gas and electricity. While increased thermal generation output reduces the need for wholesale market purchases, its financial impact can be significantly affected by market prices for coal and natural gas.

Output from PacifiCorp’s thermal plants increased by 1,055,579 megawatt-hours (“MWh”), or 2.2%, during the year ended March 31, 2006 compared to the year ended March 31, 2005. The Currant Creek Power Plant commenced full combined-cycle operation in March 2006, adding 523.0 MW of capability to PacifiCorp’s generation portfolio. Construction of the Lake Side Power Plant is progressing and is expected to begin operations in May 2007. Once in full commercial operation, the Lake Side Power Plant will add an estimated capability of 550.0 MW to meet expected future energy needs.

Output from PacifiCorp-owned hydroelectric facilities for the year ended March 31, 2006 increased by 1,074,640 MWh, or 35.0%, as compared to the year ended March 31, 2005. This increase was primarily attributable to current-year water conditions that, although slightly lower than normal, improved relative to the prior-year period. PacifiCorp’s hydroelectric generation was 98.2% of normal for the year ended March 31, 2006, based on a 30-year average. Hydroelectric generation has been below normal for the past six years. PacifiCorp cannot predict if this trend will continue in future years.

PacifiCorp continues to experience increasing employee costs primarily due to rising healthcare and pension costs, additional employees and normal annual salary and wage increases. Pension costs continue to increase as a result of

previous years' decreases in discount rates, which result in increases in PacifiCorp's projected benefit obligation, as well as the recognition of deferred losses from previous years' lower-than-expected plan asset returns.

Wholesale energy sales and purchase contracts that meet the definition of a derivative are recorded at fair value. For derivative contracts, when forward prices are higher than contract prices, wholesale energy sales contracts will have unrealized losses and wholesale purchase contracts will have unrealized gains. The opposite is true when forward prices are lower than contract prices. Unrealized gains and losses will reverse in future periods when the contracts settle at contract prices. They do not result in cash collections or payments other than in obtaining or providing cash collateral required in support of certain contracts. See "Item 8. Financial Statements -- Note 3 -- Derivative Instruments" for a summary of unrealized gains and losses on wholesale energy sales and purchase contracts.

## Year Ended March 31, 2006 Compared to Year Ended March 31, 2005

### Revenues

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2006	2005	\$ Change	% Change
Retail	\$ 2,808.6	\$ 2,648.8	\$ 159.8	6.0 %
Wholesale sales and other	1,088.1	400.0	688.1	172.0
Total revenues	<u>\$ 3,896.7</u>	<u>\$ 3,048.8</u>	<u>\$ 847.9</u>	<u>27.8</u>
Retail energy sales (thousands of MWh)	50,112	48,919	1,193	2.4
Total retail customers (in thousands)	1,640	1,605	35	2.2

**Retail revenues** increased \$159.8 million, or 6.0%, primarily due to:

- \$74.1 million of increases from higher prices approved by regulators;
- \$43.2 million of increases related to growth in the number of residential and commercial customers;
- \$28.7 million of increases due to higher average residential and industrial customer usage, net of decreases in commercial and other customer usage; and
- \$13.8 million of increases due to changes in price mix, resulting from the levels of customer usage at different customer tariffs in the various states that PacifiCorp serves.

**Wholesale sales and other revenues** increased \$688.1 million, or 172.0%, primarily due to:

- \$554.4 million of increases from higher unrealized gains on short- and long-term energy sales contracts recorded at fair value, primarily due to changes in forward prices;
- \$108.7 million of increases in wholesale electric sales, primarily due to higher prices;
- \$29.2 million of increases resulting from sales of sulfur dioxide emission allowances;
- \$11.0 million of increases in wholesale natural gas sales; and
- \$8.2 million of increases in revenues from the settlement of amounts previously disputed with third parties; partially offset by,
- \$28.2 million of decreases related to non-physically settled system balancing transactions.

### Operating Expenses

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2006	2005	\$ Change	% Change
Energy costs	\$ 1,545.1	\$ 948.0	\$ (597.1)	(63.0) %
Operations and maintenance	1,014.5	913.1	(101.4)	(11.1)
Depreciation and amortization	448.3	436.9	(11.4)	(2.6)
Taxes, other than income taxes	96.8	94.4	(2.4)	(2.5)
Total operating expenses	<u>\$ 3,104.7</u>	<u>\$ 2,392.4</u>	<u>\$ (712.3)</u>	<u>(29.8)</u>

**Energy costs** increased \$597.1 million, or 63.0%, primarily due to:

- \$469.5 million of increases from higher unrealized losses on short- and long-term energy purchase contracts recorded at fair value, primarily due to changes in forward prices;
- \$43.5 million of increases related to unfavorable changes in the fair value of streamflow weather derivative contracts resulting primarily from improved streamflow conditions in the current year compared to prior forecasts;
- \$40.7 million of increases in purchased electricity due to higher prices and volumes;
- \$14.8 million of increases related to higher volumes of coal consumed due primarily to an increase in thermal generation;
- \$13.9 million of increases related to higher prices for coal consumed; and
- \$11.2 million of increases related to higher wheeling expenses.

**Operations and maintenance expense** increased \$101.4 million, or 11.1%, primarily due to:

- \$43.7 million of increases in employee expenses, primarily due to an increase in headcount and higher benefit and pension costs;
- \$17.0 million in employee severance expense incurred during the current year;
- \$11.3 million of increases in materials and supplies utilized in plant overhaul activities;
- \$9.7 million of increases in third-party contract and service fees; and
- \$7.2 million of increases from services rendered by Scottish Power UK plc prior to the sale of PacifiCorp to MEHC, and charged to PacifiCorp pursuant to the affiliated interest cross-charge policy.

**Depreciation and amortization expense** increased \$11.4 million, or 2.6%, primarily due to:

- \$13.9 million of increases in depreciation expense due to additions to plant in service; partially offset by,
- \$3.0 million of decreases in amortization expense predominantly due to certain capitalized software becoming fully amortized.

#### Interest and Other (Income) Expense

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2006	2005	\$ Change	% Change
Interest expense	\$ 279.9	\$ 267.4	\$ (12.5)	(4.7) %
Interest income	(9.5)	(9.1)	0.4	4.4
Interest capitalized	(32.4)	(14.8)	17.6	118.9
Minority interest and other	(6.1)	(7.3)	(1.2)	(16.4)
Total	<u>\$ 231.9</u>	<u>\$ 236.2</u>	<u>\$ 4.3</u>	1.8

**Interest expense** increased \$12.5 million, or 4.7%, primarily due to:

- Higher average debt outstanding and higher variable rates during the year ended March 31, 2006; partially offset by,
- Lower average fixed rates on long-term debt during the year ended March 31, 2006.

**Interest capitalized** increased \$17.6 million, or 118.9%, primarily due to higher average construction work-in-progress balances that qualify for capitalized interest and higher capitalization rates during the year ended March 31, 2006.

**Minority interest and other expense** changed \$1.2 million, primarily due to lower gains on net investments for the year ended March 31, 2006 compared to the year ended March 31, 2005.

#### Income Tax Expense

Income tax expense increased \$30.9 million, or 18.3%, primarily due to:

- \$49.0 million of increases due to higher levels of income from continuing operations before income taxes for the year ended March 31, 2006; and

- \$9.7 million of increases in the income tax contingency reserve; partially offset by,
- \$9.2 million of decreases from the tax effect of the regulatory treatment of book and tax depreciation differences of \$3.1 million and of the regulatory treatment of other differences of \$6.1 million;
- \$5.4 million of decreases due to permanent book and tax differences of Internal Revenue Service settlements in the prior year;
- \$5.0 million of decreases from the tax effect of increases in depletion expense; and
- \$4.3 million of decreases from the tax effect of certain state income tax credits.

## Year Ended March 31, 2005 Compared to Year Ended March 31, 2004

### Revenues

(Millions of dollars)

	Year Ended March 31,		Favorable/(Unfavorable)	
	2005	2004	\$ Change	% Change
Retail	\$ 2,648.8	\$ 2,547.0	\$ 101.8	4.0 %
Wholesale sales and other	400.0	647.5	(247.5)	(38.2)
Total revenues	<u>\$ 3,048.8</u>	<u>\$ 3,194.5</u>	<u>\$ (145.7)</u>	<u>(4.6)</u>
Retail energy sales (thousands of MWh)	48,919	48,679	240	0.5
Total retail customers (in thousands)	1,605	1,570	35	2.2

**Retail revenues** increased \$101.8 million, or 4.0%, primarily due to:

- \$108.9 million of increases from higher prices approved by regulators; and
- \$49.0 million of increases relating to growth in the number of residential, commercial and industrial customers; partially offset by,
- \$39.8 million of decreases from lower average residential customer usage, net of increases in commercial usage; and
- \$7.3 million of decreases due to a change in price mix, which resulted from the levels of customer usage at different customer tariffs in the various states that PacifiCorp serves.

**Wholesale sales and other revenues** decreased \$247.5 million, or 38.2%, primarily due to:

- \$300.6 million of decreases from higher unrealized losses on short- and long-term energy sales contracts recorded at fair value, primarily due to changes in forward prices; and
- \$48.1 million of decreases related to non-physically settled system balancing transactions; partially offset by,
- \$47.2 million of increases due to higher revenues related to regulatory asset recovery, including \$27.9 million due to a new tariff in Utah;
- \$45.9 million of increases in wholesale electric sales due to higher volumes and prices; and
- \$2.8 million of increases due to higher wheeling revenue.

### Operating Expenses

(Millions of dollars)

	Year Ended March 31,		Favorable/(Unfavorable)	
	2005	2004	\$ Change	% Change
Energy costs	\$ 948.0	\$ 1,156.7	\$ 208.7	18.0 %
Operations and maintenance	913.1	895.8	(17.3)	(1.9)
Depreciation and amortization	436.9	428.8	(8.1)	(1.9)
Taxes, other than income taxes	94.4	95.3	0.9	0.9
Total operating expenses	<u>\$ 2,392.4</u>	<u>\$ 2,576.6</u>	<u>\$ 184.2</u>	<u>7.1</u>

**Energy costs** decreased \$208.7 million, or 18.0%, primarily due to:

- \$302.9 million of decreases from higher unrealized gains on short- and long-term energy purchase contracts recorded at fair value, primarily due to changes in forward prices;

- \$27.5 million of decreases due to favorable changes in fair value on streamflow weather derivative contracts; and
- \$9.9 million of decreases due to lower volumes of coal consumed due mainly to a reduction in thermal plant generation; partially offset by,
- \$98.4 million of increases in purchased electricity due to higher volumes and prices; and
- \$30.0 million of increases due to higher prices for coal consumed.

**Operations and maintenance expense** increased \$17.3 million, or 1.9%, primarily due to:

- \$44.3 million of increases in employee salary expense and other direct employee expenses, primarily due to an increase in headcount and higher benefit and pension costs;
- \$14.9 million of increases from services rendered by Scottish Power UK plc and charged to PacifiCorp pursuant to ScottishPower's affiliated interest cross-charge policy, which became effective April 1, 2004; and
- \$12.1 million of net increases due to changes in regulatory assets and liabilities, including \$27.0 million of increased Utah demand-side management amortization; partially offset by,
- \$26.9 million of decreases in third-party contract and service fees, including a reduction in the use of contractors for certain activities, including information technology, planned outages and field operations;
- \$5.5 million of a decrease due to the recognition of claims in the prior year due to the bankruptcy of an insurance carrier; and
- \$5.5 million of decreases in insurance costs.

**Depreciation and amortization expense** increased \$8.1 million, or 1.9%, primarily due to:

- \$15.8 million of increases in depreciation and amortization expense due to an increase in plant in service; and
- \$4.6 million of increases in amortization expense due to higher capitalized software balances; partially offset by,
- \$12.9 million of decreases in capitalized software amortization following a change in the estimated useful lives of certain computer software systems.

#### Interest and Other (Income) Expense

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2005	2004	\$ Change	% Change
Interest expense	\$ 267.4	\$ 256.5	\$ (10.9)	(4.2) %
Interest income	(9.1)	(13.8)	(4.7)	(34.1)
Interest capitalized	(14.8)	(19.9)	(5.1)	(25.6)
Minority interest and other	(7.3)	1.6	8.9	556.3
Total	<u>\$ 236.2</u>	<u>\$ 224.4</u>	<u>\$ (11.8)</u>	<u>(5.3)</u>

**Interest expense** increased \$10.9 million, or 4.2%, primarily due to \$8.9 million of increases resulting from an increase in average amount of debt outstanding, due in part to the refinancing of \$352.0 million of Preferred securities redeemed in August 2003 with long-term debt, partially offset by a decrease in average interest rates.

**Interest income** decreased \$4.7 million, or 34.1%, primarily due to decreases in interest income on regulatory assets.

**Interest capitalized** decreased \$5.1 million, or 25.6%, primarily due to lower average capitalization rates applied to higher qualifying construction work-in-progress balances during the year ended March 31, 2005.

**Minority interest and other expense** changed \$8.9 million, primarily due to:

- \$11.7 million of a decrease in expense relating to distributions on Preferred securities, which were redeemed in August 2003;
- \$2.3 million of a decrease in charitable donations; partially offset by,
- \$4.3 million of an increase in income relating to proceeds from company-owned life insurance.

## **Income Tax Expense**

Income tax expense increased \$24.0 million, or 16.6%, primarily due to:

- \$14.2 million of increases in the federal tax contingency reserve due to \$8.5 million of additional accruals in the current year related to new activities/development of tax examinations, compared to \$5.7 million of contingency reserve releases in the prior year due to the resolution of certain tax examinations;
- \$9.5 million of increases due to higher levels of income from continuing operations before income taxes and cumulative effect of accounting change for the year ended March 31, 2005; and
- \$5.4 million of increases due to permanent book and tax differences of Internal Revenue Service settlements; partially offset by,
- \$3.9 million of decreases from the tax effect of regulatory treatment of book and tax differences; and
- \$3.7 million of decreases in state income tax effect.

## **LIQUIDITY AND CAPITAL RESOURCES**

### **Sources and Uses of Cash**

PacifiCorp depends on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash provided by operating activities are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through sales of securities, including additional long-term debt issuances, and, in the past, also by issuance of common stock to PacifiCorp's former parent company, PHI. PacifiCorp expects it will need additional periodic equity contributions from its existing parent over the next five years. Issuance of longer-term securities is influenced by levels of short-term debt, cash from operations, capital expenditures, market conditions, regulatory approvals and other considerations.

### **Operating Activities**

Net cash flows provided by operating activities increased \$183.5 million to \$894.6 million for the year ended March 31, 2006 compared to \$711.1 million for the year ended March 31, 2005, primarily due to higher retail revenues, increased generation output, reduced net cash collateral requirements and the net impact of the timing of cash collection and payments, partially offset by increases in income tax payments and higher fuel inventory levels.

Net cash provided by operating activities decreased \$120.8 million to \$711.1 million for the year ended March 31, 2005 compared to \$831.9 million for the year ended March 31, 2004, due primarily to increases in net cash collateral requirements; increases in the level of funding for pension and other postretirement benefit plans; higher inventory levels; and the net impact of the timing of cash collection and payments.

### **Investing Activities**

Net cash used in investing activities increased \$177.4 million to \$1,024.1 million for the year ended March 31, 2006, primarily due to higher capital expenditures during the year ended March 31, 2006 compared to the prior year. Capital expenditures totaled \$1,049.0 million for the year ended March 31, 2006, compared to \$851.6 million for the year ended March 31, 2005. The increase was primarily due to \$109.7 million of increased expenditures on the construction of the Lake Side Power Plant, increases in various capital projects related to transmission and distribution and other thermal and hydroelectric facilities and \$58.5 million for the installation of emission control equipment at the Huntington Power Plant, partially offset by \$113.9 million of decreases in expenditures for the Currant Creek Plant. Expenditures for the Lake Side Power Plant will continue to be capitalized as construction work-in-progress until the plant is placed into service, which is expected to occur by May 2007. The Currant Creek Power Plant was completed in simple and combined-cycle phases. The simple-cycle phase was placed into service during May and June 2005 and combined-cycle phase was placed into service during March 2006.

Net cash used in investing activities increased \$143.2 million to \$846.7 million for the year ended March 31, 2005, primarily due to higher capital expenditures during the year ended March 31, 2005 compared to the prior year. Capital expenditures totaled \$851.6 million for the year ended March 31, 2005, compared to \$690.4 million for the year ended March 31, 2004. The increase was primarily due to \$158.9 million of increased expenditures on the

construction of the Currant Creek Power Plant and \$49.6 million for construction of the Lake Side Power Plant, partially offset by lower expenditures on the distribution and transmission upgrades along the Wasatch Front in Utah, as well as reductions in other capital expenditures.

## **Financing Activities**

### **Short-Term Debt**

PacifiCorp's short-term debt decreased by \$284.4 million during the year ended March 31, 2006 to \$184.4 million, primarily due to proceeds from long-term debt and common stock financing during the period, partially offset by capital expenditures in excess of net cash from operations. Regulatory authorities limit PacifiCorp to \$1.5 billion of short-term debt, of which \$184.4 million was outstanding at March 31, 2006, with a weighted-average interest rate of 4.8%.

PacifiCorp's short-term debt increased by \$343.9 million during the year ended March 31, 2005 to \$468.8 million, primarily due to capital expenditures in excess of net cash from operations and pre-funding of maturing long-term debt, partially offset by the proceeds from the long-term debt financing during the period. Short-term debt increased by \$99.9 million during the year ended March 31, 2004, primarily due to changes in working capital, maturing long-term debt, increased capital expenditures and the resumption of paying dividends on common shares.

### **Revolving Credit Agreement**

PacifiCorp's short-term borrowings and certain other financing arrangements are supported by an \$800.0 million committed bank revolving credit agreement, which was amended during August 2005. Changes included an increase to 65.0% in the covenant not to exceed a specified debt-to-capitalization percentage, extension of the termination date to August 2010 and exclusion of the acquisition of PacifiCorp by MEHC as an event of default under the agreement. The interest rate on advances under this facility is generally based on the London Interbank Offered Rate (LIBOR) plus a margin that varies based on PacifiCorp's credit ratings. As of March 31, 2006, this facility was fully available and there were no borrowings outstanding. In addition to this committed credit facility, at March 31, 2006, PacifiCorp had \$79.6 million in money market accounts included in Cash and cash equivalents available to meet its liquidity needs.

PacifiCorp's revolving credit agreement contains customary covenants and default provisions, which PacifiCorp monitors on a regular basis. As of March 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit agreement, which also apply to its letters of credit. See "Future Uses of Cash - Contractual Obligations and Commercial Commitments - Commercial Commitments" below for information regarding PacifiCorp's letters of credit.

### **Long-Term Debt**

During the year ended March 31, 2006, PacifiCorp made scheduled long-term debt repayments of \$269.7 million.

In June 2005, PacifiCorp issued \$300.0 million of its 5.25% Series of First Mortgage Bonds due June 15, 2035. PacifiCorp used the proceeds for the reduction of short-term debt, including the short-term debt used in December 2004 to redeem its 8.625% Series of First Mortgage Bonds due December 13, 2024 totaling \$20.0 million.

During the year ended March 31, 2005, PacifiCorp made scheduled long-term debt repayments of \$239.8 million. Additionally, during December 2004, PacifiCorp redeemed, prior to maturity, all of the 8.625% First Mortgage Bonds due December 13, 2024 totaling \$20.0 million.

In March 2005, the maturity dates for three series of variable-rate pollution-control revenue bonds totaling \$38.1 million were extended to December 1, 2020.

In August 2004, PacifiCorp issued \$200.0 million of its 4.95% Series of First Mortgage Bonds due August 15, 2014 and \$200.0 million of its 5.90% Series of First Mortgage Bonds due August 15, 2034. PacifiCorp used the proceeds for general corporate purposes, including the reduction of short-term debt.

For the year ended March 31, 2004, PacifiCorp made scheduled long-term debt repayments of \$136.6 million. Additionally, during July and August 2003, PacifiCorp redeemed, prior to maturity, First Mortgage Bonds totaling

\$57.5 million and Preferred Securities totaling \$352.0 million. These retirements were funded initially with short-term debt. In September 2003, PacifiCorp issued \$200.0 million of its 4.30% First Mortgage Bonds due September 15, 2008 and \$200.0 million of its 5.45% First Mortgage Bonds due September 15, 2013.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on:

- A percentage of utility property additions;
- Bond credits arising from retirement of previously outstanding bonds; and/or
- Deposits of cash.

The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of March 31, 2006, PacifiCorp estimated it would be able to issue up to \$4.7 billion of new First Mortgage Bonds under the most restrictive issuance test in the mortgage. Any issuances would be subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the Mortgage on the basis of property additions, bond credits and/or deposits of cash. See also "Limitations" below.

During September 2005, the SEC declared effective PacifiCorp's shelf registration statement covering \$700.0 million of future first mortgage bond and unsecured debt issuances. PacifiCorp has not yet issued any of the securities covered by this registration statement.

PacifiCorp has state regulatory authority to issue up to an additional \$700.0 million of long-term debt from the UPSC, OPUC and IPUC and up to \$100.0 million of first mortgage bonds from the WUTC. An additional filing will be made with the WUTC prior to any future issuances.

#### **Common Stock**

During the year ended March 31, 2006, PacifiCorp issued 44,884,826 shares of its common stock to PHI, its former parent company, at a total price of \$484.7 million. PacifiCorp used the proceeds from the sale of these shares for the reduction of short-term debt.

PacifiCorp expects to seek amendments to existing state regulatory authority or new authorizations that would permit the issuance of its common stock to PPW Holdings LLC.

#### **Preferred Stock Redemptions**

PacifiCorp redeemed \$7.5 million of Preferred stock subject to mandatory and optional redemption during each of the years ended March 31, 2006, 2005 and 2004.

#### **Dividends**

During the year ended March 31, 2006, PacifiCorp had the following dividend activity:

- \$175.0 million declared and paid on common stock;
- \$5.6 million declared on preferred stock and preferred stock subject to mandatory redemption, of which \$3.5 million was recorded as interest expense; and
- \$5.8 million paid on preferred stock and preferred stock subject to mandatory redemption.

On March 20, 2006, immediately prior to the closing of PacifiCorp's sale to MEHC, PacifiCorp paid a dividend on common stock, at that time held by PHI, in the aggregate amount of \$16.8 million. The dividend was reduced pursuant to Amendment No. 1 to the Stock Purchase Agreement among MEHC, ScottishPower and PHI executed on the date of the transaction's closing from the \$56.6 million aggregate amount originally declared by the PacifiCorp Board of Directors on January 27, 2006.

During the year ended March 31, 2005, PacifiCorp had the following dividend activity:

- \$193.3 million declared and paid on common stock;
- \$6.1 million declared on preferred stock and preferred stock subject to mandatory redemption, of which \$4.0 million was recorded as interest expense; and

- \$6.2 million paid on preferred stock and preferred stock subject to mandatory redemption.

During the year ended March 31, 2004, PacifiCorp had the following dividend activity:

- \$160.6 million declared and paid on common stock;
- \$6.7 million declared on preferred stock and preferred stock subject to mandatory redemption, of which \$3.4 million was recorded as interest expense; and
- \$6.8 million paid on preferred stock and preferred stock subject to mandatory redemption.

### **Capitalization**

(Millions of dollars)	March 31,			
	2006		2005	
Short-term debt	\$ 184.4	2.2 %	\$ 468.8	6.0 %
Long-term debt, including current maturities	3,937.9	47.9	3,898.9	50.0
Preferred stock subject to mandatory redemption	45.0	0.5	52.5	0.7
Preferred stock	41.3	0.5	41.3	0.5
Common equity	4,010.5	48.9	3,335.8	42.8
Total capitalization	<u>\$ 8,219.1</u>	<u>100.0 %</u>	<u>\$ 7,797.3</u>	<u>100.0 %</u>

PacifiCorp manages its capitalization and liquidity position with a key objective of retaining existing credit ratings, which is expected to facilitate continuing access to flexible borrowing arrangements at favorable costs and rates. This objective, subject to periodic review and revision, attempts to balance the interests of all shareholders, ratepayers and creditors and to provide a competitive cost of capital and predictable capital market access.

As a result of recent changes in accounting standards, such as FIN 46R, *Consolidation of Variable-Interest Entities*, an interpretation of Accounting Research Bulletin No. 51, and EITF No. 01-08, *Determining Whether an Arrangement Is a Lease*, it is possible that new purchase power and gas agreements, transmission arrangements or amendments to existing arrangements may be accounted for as capital lease obligations or debt on PacifiCorp's financial statements. While PacifiCorp has successfully amended covenants in financing arrangements that may be impacted by these changes, it may be more difficult for PacifiCorp to comply with its capitalization targets or regulatory commitments concerning minimum levels of common equity as a percentage of capitalization. This may lead PacifiCorp to seek amendments or waivers from regulators, delay or reduce dividends or spending programs, seek additional new common equity contributions from its immediate parent, PPW Holdings LLC, or take other actions.

### **Limitations**

In addition to PacifiCorp's capital structure objectives, its debt capacity is also governed by its contractual and regulatory commitments.

PacifiCorp's credit agreement contains customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 65.0%. As of March 31, 2006, management believes that PacifiCorp could have borrowed an additional \$3.3 billion without exceeding this threshold. Any additional borrowings would be subject to market conditions, and amounts may be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements.

The state regulatory orders that authorized the acquisition by MEHC contain restrictions on PacifiCorp's ability to pay common dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock

outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

## **FUTURE USES OF CASH**

### **Dividends**

PacifiCorp does not presently anticipate that it will declare dividends on common stock during the 12 months ending March 31, 2007.

### **Capital Expenditure Program**

Actual capital expenditures were \$1,049.0 million for the year ended March 31, 2006 and \$851.6 million for the year ended March 31, 2005. Estimated capital expenditures for the 12 months ending March 31, 2007 are expected to be approximately \$1.1 billion, which include \$129.2 million for emissions control equipment to address current and anticipated air quality regulations, \$137.9 million for generation development projects, and \$875.1 million for ongoing operational projects.

In conjunction with state regulatory approvals of the PacifiCorp acquisition, MEHC and PacifiCorp committed to invest \$812.0 million in capital spending for emission control equipment to address current and future air quality initiatives implemented by the EPA or by the states in which PacifiCorp operates facilities. Additional capital expenditures for emission reduction projects may be required, depending on the outcome of pending or new air quality regulations. The actual and estimated expenditures for emissions control equipment include amounts for installation of equipment at the Huntington Power Plant. The actual expenditures for the Huntington Power Plant were \$59.6 million for the year ended March 31, 2006. The estimated expenditures for the 12 months ending March 31, 2007 are \$68.7 million.

In March 2006, PacifiCorp completed construction of the Currant Creek Power Plant, a 523.0-MW combined-cycle plant in Utah. Total project costs incurred through March 31, 2006 were approximately \$338.0 million. The estimates provided above for generation development projects include the remaining costs to have the Lake Side Power Plant constructed, as well as upgrades of other generation plant equipment. As of March 31, 2006, \$208.9 million of the \$347.0 million expected total cost for the Lake Side Power Plant had been incurred.

PacifiCorp is focused on infrastructure improvement projects in targeted areas to improve customer service and network safety and enhance system reliability and performance. PacifiCorp and MEHC have committed to a number of transmission and distribution system investments in connection with regulatory approval of PacifiCorp's sale to MEHC. Approximately \$519.5 million in investments in PacifiCorp's transmission and distribution system are expected over the next several years, of which \$13.9 million are currently estimated to be incurred during the 12 months ending March 31, 2007.

All of these expenditures are subject to continuing review and revision by PacifiCorp, and actual costs could vary from estimates due to various factors, such as changes in business conditions, revised load-growth estimates, future legislative and regulatory developments, increasing costs in labor, equipment and materials, competition in the industry for similar technology and management's strategies for achieving compliance with regulations. The estimates of capital expenditures for the 12 months ending March 31, 2007 generally excludes the potential impact on generation and transmission capacity of future decisions arising from further stages of PacifiCorp's various Integrated Resource Plans. Additional expenditures may be significant but are spread over a number of years and cannot be accurately estimated at this time. Based on future decisions arising from the Integrated Resource Plan process, including wind generation projects, the estimate of capital expenditures may be revised.

In funding its capital expenditure program, PacifiCorp expects to obtain funds required for construction and other purposes from sources similar to those used in the past, including operating cash flows, the issuance of new long-term and short-term debt and equity contributions from MEHC.

## Contractual Obligations and Commercial Commitments

### Contractual Obligations

The table below shows PacifiCorp's contractual obligations as of March 31, 2006.

(Millions of dollars)	Payments due during the 12 months ending March 31,				
	2007	2008-2009	2010-2011	Thereafter	Total
Long-term debt, including interest:					
Fixed-rate obligations	\$ 429.8	\$ 911.7	\$ 479.9	\$ 4,223.0	\$ 6,044.4
Variable-rate obligations (a)	17.4	34.8	34.8	690.9	777.9
Short-term debt, including interest	185.0	-	-	-	185.0
Preferred stock subject to mandatory redemption	3.7	41.3	-	-	45.0
Capital leases, including interest	4.8	9.6	9.9	63.8	88.1
Operating leases (b)	15.0	18.2	4.2	8.8	46.2
Asset retirement obligations (c)	7.0	34.0	35.8	356.7	433.5
Power purchase agreements: (d)					
Electricity commodity contracts	603.2	380.5	211.4	667.2	1,862.3
Electricity capacity contracts	136.9	299.6	310.4	1,301.1	2,048.0
Electricity mixed contracts	16.2	30.7	26.8	178.4	252.1
Transmission	45.7	77.2	72.1	503.3	698.3
Fuel purchase agreements: (d)					
Natural gas supply and transportation	317.4	678.8	433.8	869.3	2,299.3
Coal supply and transportation	199.4	444.2	358.7	1,062.2	2,064.5
Purchase obligations (e)	123.2	42.0	2.2	3.1	170.5
Owned hydroelectric commitments (f)	28.8	71.7	66.7	469.9	637.1
Other long-term liabilities (g)	5.0	6.0	2.3	7.3	20.6
Total contractual cash obligations	<u>\$ 2,138.5</u>	<u>\$ 3,080.3</u>	<u>\$ 2,049.0</u>	<u>\$ 10,405.0</u>	<u>\$ 17,672.8</u>

- (a) Consists of principal and interest for pollution-control revenue bond obligations with interest rates scheduled to reset within the next 12 months. Future variable interest rates are set at March 31, 2006 rates. See "Item 7A. Interest Rate Risk" for additional discussion related to variable-rate liabilities.
- (b) Excluded from these amounts are power purchase agreements that meet the definition of an operating lease. Such amounts are included with power purchase agreements.
- (c) Represents expected cash payments adjusted for inflation for estimated costs to perform legally required asset retirement activities.
- (d) Commodity contracts are agreements for the delivery of energy. Capacity contracts are agreements that provide rights to the energy output of a specified facility. Forecasted or other applicable estimated prices were used to determine total dollar value of the commitments for purposes of the table. Amounts included in power purchase agreements include those agreements that meet the definition of an operating lease.
- (e) Includes minimum commitments for maintenance, outsourcing of certain services, contracts for software, telephone, data and consulting or advisory services. Also includes contractual obligations for engineering, procurement and construction costs on the Lake Side Power Plant and Huntington Power Plant emission control equipment.
- The purchase obligation amounts consist of items for which PacifiCorp is contractually obligated to purchase from a third party as of March 31, 2006. These amounts only constitute the known portion of PacifiCorp's expected future expenses; therefore, the amounts presented in the table will not provide a reliable indicator of PacifiCorp's expected future cash outflows on a stand-alone basis. For purposes of identifying and accumulating purchase obligations, PacifiCorp has included all contracts meeting the definition of a purchase obligation (e.g., legally binding and specifying all significant terms, including fixed or minimum amount or quantity to be purchased and the approximate timing of the transaction). For those contracts involving a fixed or minimum quantity but variable pricing, PacifiCorp has estimated the contractual obligation based on its best estimate of pricing that will be in effect at the time the obligation is incurred.
- (f) PacifiCorp has entered into settlement agreements with various interested parties to resolve issues necessary to

obtain new hydroelectric licenses from the FERC. These settlement agreements generally include clauses that allow for termination of certain of PacifiCorp's obligations if the FERC license order is not consistent with the settlement agreement. The table only includes contractual obligations made in settlement agreements that are not contingent upon the FERC license being consistent with the settlement agreement and obligations that are required by the FERC licenses. Hydroelectric licenses have varying expiration dates, and several expire within the next five years. The contractual obligations included in the table expire with the license expiration dates. However, PacifiCorp plans to acquire new licenses that will allow for continued operation for more than 30 years and expects contractual obligations to continue or increase.

- (g) Includes environmental commitments recorded on the balance sheet that are contractually or legally binding. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete year.

### **Commercial Commitments**

At March 31, 2006, PacifiCorp had \$517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately \$40.5 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of March 31, 2006 and expire periodically through the 12 months ending March 31, 2011.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants to those contained in PacifiCorp's revolving credit agreement. See "Financing Activities – Revolving Credit Agreement" for further information. However, the maximum debt-to-capitalization ratio for one of these arrangements was 60.0% as of March 31, 2006 and was amended in May 2006 to now permit a maximum ratio of 65.0%. PacifiCorp monitors these covenants on a regular basis and at March 31, 2006, was in compliance with the covenants of these agreements.

PacifiCorp's commercial commitments include surety bonds that provide indemnities for PacifiCorp in relation to various commitments it has to third parties for obligations in the event of default on behalf of PacifiCorp. The majority of these bonds are continuous in nature and renew annually. Based on current contractual commitments, PacifiCorp's level of surety bonding beyond the year ended March 31, 2006, is estimated to be approximately \$27.3 million. This estimate is based on current information and actual amounts may vary due to rate changes or changes to the general operations of PacifiCorp.

### **CREDIT RATINGS**

PacifiCorp's credit ratings at March 31, 2006, were as follows:

	Moody's	Standard & Poor's
Issuer/Corporate	Baa1	A-
Senior secured debt	A3	A-
Senior unsecured debt	Baa1	BBB+
Preferred stock	Baa3	BBB
Commercial paper	P-2	A-1
Outlook	Stable	Stable

In February 2006, Moody's Investors Service affirmed the issuer and securities ratings of PacifiCorp and changed the ratings outlook to stable from developing. In March 2006, Standard & Poor's Rating Services affirmed the corporate credit ratings and securities ratings of PacifiCorp and changed the ratings outlook to stable from CreditWatch with negative implications. Also in March 2006, Standard & Poor's Rating Services raised the short-term rating for PacifiCorp to A-1 from A-2.

PacifiCorp has no rating-downgrade triggers that would accelerate the maturity dates of its debt. A change in ratings is not an event of default, nor is the maintenance of a specific minimum level of credit rating a condition to drawing upon PacifiCorp's credit agreement. However, interest rates on loans under the revolving credit agreement and

commitment fees are tied to credit ratings and would increase or decrease when ratings are changed. A ratings downgrade may reduce the accessibility and increase the cost of PacifiCorp's commercial paper program, its principal source of short-term borrowing, and may result in the requirement that PacifiCorp post collateral under certain of PacifiCorp's power purchase and other agreements. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment-grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In conjunction with its risk management activities, PacifiCorp must meet credit quality standards as required by counterparties. In accordance with industry practice, contractual agreements that govern PacifiCorp's energy management activities either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed certain ratings-dependent threshold levels or provide the right for counterparties to demand "adequate assurances" in the event of a material adverse change in PacifiCorp's creditworthiness. If one or more of PacifiCorp's credit ratings decline below investment grade, PacifiCorp would be required to post cash collateral, letters of credit or other similar credit support to facilitate ongoing wholesale energy management activities. As of March 31, 2006, PacifiCorp's credit ratings from Standard & Poor's and Moody's were investment grade; however, if the ratings fell more than one rating below investment grade, PacifiCorp's estimated potential collateral requirements totaled approximately \$334.0 million. PacifiCorp's potential collateral requirements could fluctuate considerably due to seasonality, market prices and their volatility, a loss of key PacifiCorp generating facilities or other related factors.

#### **OFF-BALANCE SHEET ARRANGEMENTS**

PacifiCorp from time to time enters into arrangements in the normal course of business to facilitate commercial transactions with third parties that involve guarantee, indemnification or similar arrangements. PacifiCorp currently has indemnification obligations for breaches of warranties or covenants in connection with the sale of certain assets. In addition, PacifiCorp evaluates potential obligations that arise out of variable interests in unconsolidated entities, determined in accordance with the FASB Interpretation No. 46, *Consolidation of Variable-Interest Entities*, an interpretation of Accounting Research Bulletin No. 51. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote. See "Item 8. Financial Statements and Supplementary Data – Note 11 – Guarantees and Other Commitments" and "Note 13 – Consolidation of Variable-Interest Entities" for more information on these obligations and arrangements.

#### **INFLATION**

PacifiCorp is subject to rate-of-return regulation and the impact of inflation on the level of cost recovery under regulation varies by state depending upon the type of test-period convention used in the state. In PacifiCorp's state jurisdictions, a 12-month period of historical costs is typically used as the basis for developing a "test year," which may also include various adjustments to eliminate abnormal or one time events, normalize cost levels, or escalate the historical costs to a future level when the new rates will actually be in effect. To the extent that the levels of costs beyond the historical 12-month period can be established either through known adjustments or through the escalation of cost levels in establishing prices, PacifiCorp can mitigate the impacts of inflationary pressures. The majority of PacifiCorp's retail customer prices are established using forecasts. These forecasts may include, but are not limited to, projected rate base levels and expenses, which are adjusted for both inflation and known and measurable changes. They may also include projected revenue and power cost changes related to load growth.

## **ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

PacifiCorp participates in a wholesale energy market that includes public utility companies, electricity and natural gas marketers, financial institutions, industrial companies and government entities. A variety of products exist in this market, ranging from electricity and natural gas purchases and sales for physical delivery to financial instruments such as futures, swaps, options and other complex derivatives. Transactions may be conducted directly with customers and suppliers, through brokers, or with an exchange that serves as a central clearing mechanism.

PacifiCorp is subject to the various risks inherent in the energy business, including credit risk, interest rate risk and commodity price risk.

### **Risk Management**

PacifiCorp has a risk management committee that is responsible for the oversight of market and credit risk relating to the commodity transactions of PacifiCorp. To limit PacifiCorp's exposure to market and credit risk, the risk management committee sets policies and limits and approves commodity strategies, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. The risk management process established by PacifiCorp is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business and activities and to measure quantitative market risk exposure and identify qualitative market risk exposure in its businesses. To assist in managing the volatility relating to these exposures, PacifiCorp enters into various transactions, including derivative transactions, consistent with PacifiCorp's risk management policy and procedures. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage activities to take advantage of market inefficiencies. The policy and procedures also govern PacifiCorp's use of derivative instruments for commodity derivative transactions, as well as its energy purchase and sales practices, and describe PacifiCorp's credit policy and management information systems required to effectively monitor such derivative use. PacifiCorp's risk management policy provides for the use of only those instruments that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions, thereby ensuring that such instruments will be primarily used for hedging. PacifiCorp's portfolio of energy derivatives is substantially used for non-trading purposes.

PacifiCorp continues to actively manage its exposure to commodity price volatility. These activities may include adding to the generation portfolio and entering into transactions that help to shape PacifiCorp's system resource portfolio, including wholesale contracts and financially settled temperature-related derivative instruments that reduce volume and price risk due to weather extremes.

### **Credit Risk**

Credit risk relates to the risk of loss that might occur as a result of non-performance by counterparties of their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with such counterparty.

PacifiCorp seeks to mitigate credit risk (and concentrations of credit risk) by applying specific eligibility criteria to prospective counterparties. However, despite mitigation efforts, defaults by counterparties occur from time to time. PacifiCorp continues to actively monitor the creditworthiness of counterparties with whom it transacts and uses a variety of risk mitigation techniques to limit its exposure as it believes appropriate. When PacifiCorp considers a new asset purchase, transaction or contractual arrangement, market liquidity and the ability to optimize the

investment are main considerations. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp has entered into netting and collateral arrangements that include margining and cross-product netting agreements and obtaining third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed receipts. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

The following table represents PacifiCorp's March 31, 2006 distribution of unsecured credit exposure, net of collateral, within its electricity and natural gas portfolio of purchase and sale contracts and takes into account contractual netting rights.

Distribution of Credit Exposure	% of Total
Investment grade - Externally rated	81.6 %
Non-investment grade - Externally rated	0.1
Investment grade - Internally rated	0.2
Non-investment grade - Internally rated	18.1
	<u>100.0 %</u>

"Externally rated" represents enterprise relationships that have published ratings from at least one major credit rating agency. "Internally rated" represents those relationships that have no rating by a major credit rating agency. For those relationships, PacifiCorp utilizes internally developed, commercially appropriate rating methodologies and credit scoring models to develop a public rating equivalent.

The "Non-investment grade - Internally rated" component of PacifiCorp's overall credit exposure reflects the market value of a small number of contracts that support PacifiCorp's Integrated Resource Plan and Oregon's electric energy restructuring legislation as it relates to renewable energy projects, as well as compliance with FERC regulations requiring utilities to purchase power from qualifying facilities.

## Interest Rate Risk

PacifiCorp is exposed to risk resulting from changes in interest rates as a result of its issuance of variable-rate debt and commercial paper. PacifiCorp manages its interest rate exposure by maintaining a blend of fixed-rate and variable-rate debt and by monitoring the effects of market changes in interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by PacifiCorp's pension plan assets, mining reclamation trust funds and cash balances. PacifiCorp's principal sources of variable-rate debt are commercial paper and pollution-control revenue bonds remarketed on a periodic basis. Commercial paper is periodically refinanced with fixed-rate debt when needed and when interest rates are considered favorable. PacifiCorp may also enter into financial derivative instruments, including interest rate swaps, swaptions and United States Treasury lock agreements, to manage and mitigate interest rate exposure. PacifiCorp does not anticipate using financial derivatives as the principal means of managing interest rate exposure. PacifiCorp's weighted-average cost of debt is recoverable in rates. Increases or decreases in interest rates are reflected in PacifiCorp's cost of debt calculation as rate cases are filed. Any adverse change to PacifiCorp's credit rating could negatively impact PacifiCorp's ability to borrow and the interest rates that are charged.

As of March 31, 2006, PacifiCorp had fixed-rate long-term liabilities of \$3,405.4 million in aggregate principal amount and having a fair value of \$3,597.1 million. These instruments have fixed interest rates and therefore do not expose PacifiCorp to the risk of earnings loss due to changes in market interest rates. However, the fair value of these instruments would decrease by approximately \$114.3 million if interest rates were to increase by 10.0% from their levels at March 31, 2006. In general, such a decrease in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity.

As of March 31, 2006, PacifiCorp had \$726.1 million of variable-rate liabilities and \$113.6 million of temporary cash investments compared to \$1,010.5 million of variable-rate liabilities and \$182.2 million of temporary cash investments at March 31, 2005. At March 31, 2006 and 2005, PacifiCorp had no financial derivatives in effect relating to interest rate exposure.

Based on a sensitivity analysis as of March 31, 2006, for a one-year horizon, PacifiCorp estimates that if market interest rates average 1.0% higher (lower) during the 12 months ending March 31, 2007 than during the year ended March 31, 2006, interest expense, net of offsetting impacts on interest income, would increase (decrease) by \$6.1 million. Comparatively, based on a sensitivity analysis as of March 31, 2005, for a one-year horizon, had interest rates averaged 1.0% higher (lower) during the year ended March 31, 2006 than during the year ended March 31, 2005, PacifiCorp estimated that interest expense, net of offsetting impacts in interest income, would have increased (decreased) by \$8.3 million. These amounts include the effect of invested cash and were determined by considering the impact of the hypothetical interest rates on the variable-rate securities outstanding as of March 31, 2006 and 2005. The decrease in interest rate sensitivity is primarily due to the decrease in outstanding variable-rate commercial paper, partially offset by the decrease in invested cash. If interest rates change significantly, PacifiCorp might take actions to manage its exposure to the change. However, due to the uncertainty of the specific actions that might be taken and their possible effects, the sensitivity analysis assumes no changes in PacifiCorp's financial structure.

### **Commodity Price Risk**

PacifiCorp's exposure to market risk due to commodity price change is primarily related to its fuel and electricity commodities, which are subject to fluctuations due to unpredictable factors, such as weather, electricity demand and plant performance, that affect energy supply and demand. PacifiCorp's energy purchase and sales activities are governed by PacifiCorp's risk management policy and the risk levels established as part of that policy.

PacifiCorp's energy commodity price exposure arises primarily from its electric supply obligation in the western United States. PacifiCorp manages this risk principally through the operation of its generation plants with a net capability of 8,470.4 MW, as well as transmission rights held both on some of its own 15,580-mile transmission system and on third-party transmission systems, and through its wholesale energy purchase and sales activities. Wholesale contracts are utilized primarily to balance PacifiCorp's physical excess or shortage of net electricity for future time periods. Financially settled contracts are utilized to further mitigate commodity price risk. PacifiCorp may from time to time enter into other financially settled, temperature-related derivative instruments that reduce volume and price risk on days with weather extremes. In addition, a financially settled hydroelectric streamflow hedge is in place through September 2006 to reduce volume and price risks associated with PacifiCorp's hydroelectric generation resources.

PacifiCorp measures the market risk in its electricity and natural gas portfolio daily, utilizing a historical Value-at-Risk ("VaR") approach and other measurements of net position. PacifiCorp also monitors its portfolio exposure to market risk in comparison to established thresholds and measures its open positions subject to price risk in terms of quantity at each delivery location for each forward time period.

VaR computations for the electricity and natural gas commodity portfolio are based on a historical simulation technique, utilizing historical price changes over a specified (holding) period to simulate potential forward energy market price curve movements to estimate the potential unfavorable impact of such price changes on the portfolio positions scheduled to settle within the following 24 months. The quantification of market risk using VaR provides a consistent measure of risk across PacifiCorp's continually changing portfolio. VaR represents an estimate of possible changes at a given level of confidence in fair value that would be measured on its portfolio assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur.

PacifiCorp's VaR computations for its electricity and natural gas commodity portfolio utilize several key assumptions, including a 99.0% confidence level for the resultant price changes and a holding period of five business days. The calculation includes short-term derivative commodity instruments held for risk mitigation and balancing purposes, the expected resource and demand obligations from PacifiCorp's long-term contracts, the expected generation levels from PacifiCorp's generation assets and the expected retail and wholesale load levels. The portfolio reflects flexibility contained in contracts and assets, which accommodate the normal variability in PacifiCorp's demand obligations and generation availability. These contracts and assets are valued to reflect the variability PacifiCorp experiences as a load-serving entity. Contracts or assets that contain flexible elements are often referred to as having embedded options or option characteristics. These options provide for energy volume changes that are sensitive to market price changes. Therefore, changes in the option values affect the energy

position of the portfolio with respect to market prices, and this effect is calculated daily. When measuring portfolio exposure through VaR, these position changes that result from the option sensitivity are held constant through the historical simulation to avoid understating VaR.

As of March 31, 2006, PacifiCorp's estimated potential five-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 24 months was \$22.4 million, as measured by the VaR computations described above, compared to \$15.5 million as of March 31, 2005. The minimum, average and maximum daily VaR (five-day holding periods) for the years ended March 31, 2006 and 2005 are as follows:

(Millions of dollars)	2006	-2005
Minimum VaR (measured)	\$ 6.7	\$ 10.6
Average VaR (calculated)	16.9	16.6
Maximum VaR (measured)	46.2	26.3

PacifiCorp maintained compliance with its VaR limit procedures during the year ended March 31, 2006. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits.

### Fair Value of Derivatives

The following table shows the changes in the fair value of energy-related contracts subject to the requirements of SFAS No. 133 from April 1, 2005, to March 31, 2006 and quantifies the reasons for the changes.

(Millions of dollars)	Net Asset (Liability)		Regulatory Net Asset (Liability) (b)
	Trading	Non-trading	
Fair value of contracts outstanding at March 31, 2005	\$ 0.2	\$ (154.4)	\$ 170.0
Contracts realized or otherwise settled during the period	(0.2)	(115.8)	128.3
Other changes in fair values (a)	0.2	277.9	(203.6)
Fair value of contracts outstanding at March 31, 2006	<u>\$ 0.2</u>	<u>\$ 7.7</u>	<u>\$ 94.7</u>

- (a) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates, including those based on models, on new and existing contracts.
- (b) Net unrealized losses (gains) related to derivative contracts included in rates are recorded as a regulatory net asset (liability).

The fair value of derivative instruments is determined using forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement of a commodity at future dates. PacifiCorp bases its forward price curves upon market price quotations when available and internally developed and commercial models with internal and external fundamental data inputs when market quotations are unavailable. In general, PacifiCorp estimates the fair value of a contract by calculating the present value of the difference between the prices in the contract and the applicable forward price curve. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years, and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, PacifiCorp must develop forward price curves. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. Factors used in the fundamentals model include the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of electricity plants in converting fuel to electricity) in the region where the purchase or sale takes place and a fundamental forecast of expected spot prices based on

modeled supply and demand in the region. The assumptions in these models are critical since any changes to the assumptions could have a significant impact on the fair value of the contract. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward and option components. Forward components are valued against the appropriate forward price curve. The optionality is valued using a modified Black-Scholes model or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve.

PacifiCorp's valuation models and assumptions are continuously updated to reflect current market information, and evaluations and refinements of model assumptions are performed on a periodic basis.

The following table shows summarized information with respect to valuation techniques and contractual maturities of PacifiCorp's energy-related contracts qualifying as derivatives under SFAS No. 133 as of March 31, 2006.

(Millions of dollars)	Fair Value of Contracts at Period-End				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
Trading:					
Values based on quoted market prices from third-party sources	\$ 0.2	\$ -	\$ -	\$ -	\$ 0.2
Non-trading:					
Values based on quoted market prices from third-party sources	\$ 58.7	\$ 49.7	\$ 6.0	\$ 1.2	\$ 115.6
Values based on models and other valuation methods	64.9	82.9	4.9	(260.6)	(107.9)
Total non-trading	\$ 123.6	\$ 132.6	\$ 10.9	\$ (259.4)	\$ 7.7
Regulatory net asset (liability)	\$ (76.2)	\$ (83.4)	\$ (5.5)	\$ 259.8	\$ 94.7

Standardized derivative contracts that are valued using market quotations are classified as "values based on quoted market prices from third-party sources." All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as "values based on models and other valuation methods." Both classifications utilize market curves as appropriate for the first six years.

PacifiCorp currently has a non-exchange traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. Under the agreement, PacifiCorp pays an annual premium in return for the right to make or receive payments if streamflow levels are above or below certain thresholds. PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flow under the contract in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. The net asset (liability) recorded for this contract was \$(2.1) million at March 31, 2006 and \$20.3 million at March 31, 2005. PacifiCorp recognized a loss of \$15.6 million for the year ended March 31, 2006; a gain of \$27.9 million for the year ended March 31, 2005; and a gain of \$0.4 million for the year ended March 31, 2004.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common shareholder's equity and cash flows present fairly, in all material respects, the financial position of PacifiCorp and its subsidiaries at March 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2006, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the consolidated financial statements, PacifiCorp and its subsidiaries changed the manner in which they apply the normal purchases and normal sales exception to derivative contracts entered into or modified after June 30, 2003, upon their adoption of SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, as of July 1, 2003.

As discussed in Note 6 to the consolidated financial statements, PacifiCorp and its subsidiaries changed the manner in which they account for asset retirement obligations upon adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations*, as of April 1, 2003.

PricewaterhouseCoopers LLP  
Portland, Oregon  
May 26, 2006

**PACIFICORP AND SUBSIDIARIES**  
**CONSOLIDATED STATEMENTS OF INCOME**

(Millions of dollars)

	Years Ended March 31,		
	2006	2005	2004
Revenues	\$ 3,896.7	\$ 3,048.8	\$ 3,194.5
Operating expenses:			
Energy costs	1,545.1	948.0	1,156.7
Operations and maintenance	1,014.5	913.1	895.8
Depreciation and amortization	448.3	436.9	428.8
Taxes, other than income taxes	96.8	94.4	95.3
Total	3,104.7	2,392.4	2,576.6
Income from operations	792.0	656.4	617.9
Interest expense and other (income) expense:			
Interest expense	279.9	267.4	256.5
Interest income	(9.5)	(9.1)	(13.8)
Interest capitalized	(32.4)	(14.8)	(19.9)
Minority interest and other	(6.1)	(7.3)	1.6
Total	231.9	236.2	224.4
Income from operations before income tax expense and cumulative effect of accounting change	560.1	420.2	393.5
Income tax expense	199.4	168.5	144.5
Income before cumulative effect of accounting change	360.7	251.7	249.0
Cumulative effect of accounting change (less applicable income tax benefit of \$(0.6)/2004	-	-	(0.9)
Net income	360.7	251.7	248.1
Preferred dividend requirement	(2.1)	(2.1)	(3.3)
Earnings on common stock	\$ 358.6	\$ 249.6	\$ 244.8

The accompanying notes are an integral part of these consolidated financial statements.

**PACIFICORP AND SUBSIDIARIES**  
**CONSOLIDATED BALANCE SHEETS**

(Millions of dollars)

	March 31,	
	2006	2005
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$ 119.6	\$ 199.3
Accounts receivable less allowance for doubtful accounts of \$11.4/2006 and \$11.6/2005	266.8	293.0
Unbilled revenue	148.2	143.8
Amounts due from affiliates - ScottishPower	-	36.5
Inventories at average costs:		
Materials and supplies	131.2	114.7
Fuel	80.9	58.5
Current derivative contract asset	221.7	252.7
Other	46.9	115.8
Total current assets	1,015.3	1,214.3
Property, plant and equipment:		
Generation	5,686.3	5,238.7
Transmission	2,591.8	2,507.7
Distribution	4,502.8	4,308.7
Intangible plant	659.0	607.0
Other	1,662.5	1,596.9
Total operating assets	15,102.4	14,259.0
Accumulated depreciation and amortization	(5,611.5)	(5,361.8)
Net operating assets	9,490.9	8,897.2
Construction work-in-progress	618.3	593.4
Total property, plant and equipment, net	10,109.2	9,490.6
Other assets:		
Regulatory assets	884.3	972.8
Derivative contract regulatory asset	94.7	170.0
Non-current derivative contract asset	345.3	360.3
Deferred charges and other	282.5	312.9
Total other assets	1,606.8	1,816.0
Total assets	\$ 12,731.3	\$ 12,520.9

The accompanying notes are an integral part of these consolidated financial statements.

**PACIFICORP AND SUBSIDIARIES**  
**CONSOLIDATED BALANCE SHEETS, continued**

(Millions of dollars)

	March 31,	
LIABILITIES AND SHAREHOLDERS' EQUITY	2006	2005
Current liabilities:		
Accounts payable	\$ 361.3	\$ 350.4
Amounts due to affiliates - MidAmerican	3.8	-
Amounts due to affiliates - ScottishPower	-	3.9
Accrued employee expenses	118.0	134.3
Taxes payable	47.0	39.8
Interest payable	63.0	64.8
Current derivative contract liability	97.9	136.7
Current deferred tax liability	16.9	2.0
Long-term debt and capital lease obligations, currently maturing	216.9	269.9
Preferred stock subject to mandatory redemption, currently maturing	3.7	3.7
Notes payable and commercial paper	184.4	468.8
Other	103.2	123.4
Total current liabilities	<u>1,216.1</u>	<u>1,597.7</u>
Deferred credits:		
Deferred income taxes	1,621.2	1,629.0
Investment tax credits	67.6	75.6
Regulatory liabilities	804.7	806.0
Non-current derivative contract liability	461.2	630.5
Pension and other post employment liabilities	385.0	422.4
Other	361.4	304.8
Total deferred credits	<u>3,701.1</u>	<u>3,868.3</u>
Long-term debt and capital lease obligations, net of current maturities	3,721.0	3,629.0
Preferred stock subject to mandatory redemption, net of current maturities	41.3	48.8
Total liabilities	<u>8,679.5</u>	<u>9,143.8</u>
Commitments, contingencies and guarantees (See Notes 10 and 11)		
Shareholders' equity:		
Preferred stock	41.3	41.3
Common equity:		
Common shareholder's capital	3,381.9	2,894.1
Retained earnings	630.0	446.4
Accumulated other comprehensive income (loss):		
Unrealized gain on available-for-sale securities, net of tax of \$1.7/2006 and \$2.6/2005	2.7	4.3
Minimum pension liability, net of tax of \$(2.5)/2006 and \$(5.5)/2005	(4.1)	(9.0)
Total common equity	<u>4,010.5</u>	<u>3,335.8</u>
Total shareholders' equity	<u>4,051.8</u>	<u>3,377.1</u>
Total liabilities and shareholders' equity	<u>\$ 12,731.3</u>	<u>\$ 12,520.9</u>

The accompanying notes are an integral part of these consolidated financial statements.

**PACIFICORP AND SUBSIDIARIES**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Cash flows from operating activities:			
Net income	\$ 360.7	\$ 251.7	\$ 248.1
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change, net of tax	-	-	0.9
Unrealized gain on derivative contracts, net	(86.8)	(8.4)	(6.1)
Depreciation and amortization	448.3	436.9	428.8
Deferred income taxes and investment tax credits, net	13.9	120.0	80.5
Regulatory asset/liability establishment and amortization	51.6	66.7	111.1
Other	50.0	(27.0)	(6.5)
Changes in:			
Accounts receivable, prepayments and other current assets	71.1	(137.8)	(1.7)
Inventories	(38.9)	(16.2)	14.1
Amounts due to/from affiliates - MidAmerican, net	3.6	-	-
Amounts due to/from affiliates - ScottishPower, net	32.6	(32.8)	(36.8)
Accounts payable and accrued liabilities	(13.4)	84.1	(3.3)
Other	1.9	(26.1)	2.8
Net cash provided by operating activities	894.6	711.1	831.9
Cash flows from investing activities:			
Capital expenditures	(1,049.0)	(851.6)	(690.4)
Proceeds from sales of assets	1.3	7.1	3.3
Proceeds from available-for-sale securities	123.4	49.1	95.8
Purchases of available-for-sale securities	(84.9)	(44.7)	(89.4)
Other	(14.9)	(6.6)	(22.8)
Net cash used in investing activities	(1,024.1)	(846.7)	(703.5)
Cash flows from financing activities:			
Changes in short-term debt	(284.4)	343.9	99.9
Proceeds from long-term debt, net of issuance costs	296.0	395.2	396.7
Proceeds from issuance of common stock to PHI	484.7	-	-
Dividends paid	(177.1)	(195.4)	(165.1)
Repayments and redemptions of long-term debt	(269.7)	(259.8)	(194.1)
Repayment of preferred securities	-	-	(352.0)
Redemptions of preferred stock	(7.5)	(7.5)	(7.5)
Other	7.8	-	(0.3)
Net cash provided by (used in) financing activities	49.8	276.4	(222.4)
Change in cash and cash equivalents	(79.7)	140.8	(94.0)
Cash and cash equivalents at beginning of period	199.3	58.5	152.5
Cash and cash equivalents at end of period	\$ 119.6	\$ 199.3	\$ 58.5

The accompanying notes are an integral part of these consolidated financial statements.

**PACIFICORP AND SUBSIDIARIES**  
**CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY**

(Millions of dollars, thousands of shares)

	Common Shareholder's Capital		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Comprehensive Income (Loss)
	Shares	Amounts			
Balance at March 31, 2003	312,176	\$ 2,892.1	\$ 305.9	\$ (3.6)	
Comprehensive income					
Net income	-	-	248.1	-	\$ 248.1
Other comprehensive income (loss):					
Unrealized gain on available-for-sale securities, net of tax of \$3.8	-	-	-	6.2	6.2
Minimum pension liability, net of tax of \$(3.8)	-	-	-	(6.1)	(6.1)
Cash dividends declared:					
Preferred stock	-	-	(3.3)	-	-
Common stock (\$0.51 per share)	-	-	(160.6)	-	-
Balance at March 31, 2004	312,176	2,892.1	390.1	(3.5)	<u>\$ 248.2</u>
Comprehensive income					
Net income	-	-	251.7	-	\$ 251.7
Other comprehensive loss:					
Unrealized loss on available-for-sale securities, net of tax of \$(0.1)	-	-	-	(0.2)	(0.2)
Minimum pension liability, net of tax of \$(0.6)	-	-	-	(1.0)	(1.0)
Stock-based compensation expense	-	2.0	-	-	-
Cash dividends declared:					
Preferred stock	-	-	(2.1)	-	-
Common stock (\$0.62 per share)	-	-	(193.3)	-	-
Balance at March 31, 2005	312,176	2,894.1	446.4	(4.7)	<u>\$ 250.5</u>
Comprehensive income					
Net income	-	-	360.7	-	\$ 360.7
Other comprehensive income (loss):					
Unrealized loss on available-for-sale securities, net of tax of \$(0.9)	-	-	-	(1.6)	(1.6)
Minimum pension liability, net of tax of \$3.0	-	-	-	4.9	4.9
Common stock issuance	44,885	484.7	-	-	-
Tax benefit from stock option exercises	-	7.5	-	-	-
Separation of employee benefit plans	-	(3.5)	-	-	-
Other	-	(0.9)	-	-	-
Cash dividends declared:					
Preferred stock	-	-	(2.1)	-	-
Common stock (\$0.53 per share)	-	-	(175.0)	-	-
Balance at March 31, 2006	<u>357,061</u>	<u>\$ 3,381.9</u>	<u>\$ 630.0</u>	<u>\$ (1.4)</u>	<u>\$ 364.0</u>

The accompanying notes are an integral part of these consolidated financial statements.

**PACIFICORP AND SUBSIDIARIES**  
**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS**

**Note 1 - Summary of Significant Accounting Policies**

On March 21, 2006, MidAmerican Energy Holdings Company ("MEHC") completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. ("PHI"), a subsidiary of Scottish Power plc ("ScottishPower"), pursuant to the Stock Purchase Agreement among MEHC, ScottishPower and PHI dated May 23, 2005, as amended on March 21, 2006. The cash purchase price was \$5.1 billion. PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities, which includes both common and preferred stock. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc.

**Nature of operations** - PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States electricity company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp generates electricity and also engages in electricity sales and purchases on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining and other fuel-related services, as well as environmental remediation.

As a result of a settlement agreement between MEHC, the Utah Committee of Consumer Services and Utah Industrial Energy Consumers, MEHC contributed to PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Intermountain Geothermal Company therefore became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC.

**Basis of presentation** - The Consolidated Financial Statements of PacifiCorp include its integrated electric utility operations and its wholly owned and majority-owned subsidiaries. Intercompany transactions and balances have been eliminated upon consolidation.

**Regulation** - Accounting for the electric utility business conforms to accounting principles generally accepted in the United States as applied to regulated public utilities and as prescribed by agencies and the commissions of the various locations in which the electric utility business operates. PacifiCorp prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") as further discussed in Note 2 - Accounting for the Effects of Regulation.

**Use of estimates** - The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities at the date of the financial statements. These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management's control. As a result, actual results could differ materially from these estimates.

**Reclassifications** - Certain reclassifications of prior years' amounts have been made to conform to the fiscal 2006 method of presentation. These reclassifications had no effect on previously reported consolidated net income.

**Cash and cash equivalents** - For the purposes of these financial statements, PacifiCorp considers all liquid investments with maturities of three months or less, at the time of acquisition, to be cash equivalents.

**Accounts receivable and allowance for doubtful accounts** - Accounts receivable includes billed retail and wholesale services plus any accrued and unpaid interest. Credit is granted to customers, which include retail and wholesale customers, government agencies and other utilities. Management performs continuing credit evaluations of customers' financial conditions, and although PacifiCorp does not require collateral, deposits may be required from customers in certain circumstances. Accounts receivable are considered delinquent based on regulations provided by

each state, which is generally if payment is not received by the date due, typically 30 days after the invoice date. PacifiCorp charges interest on delinquent customer accounts or past due balances in the states where PacifiCorp does business based on the respective regulation of each state, and this interest varies between 1.0% to 1.7% per month.

Management reviews accounts receivable on a monthly basis to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific accounts, primarily for wholesale accounts receivable, and a reserve for retail accounts receivable based on historical experience. After all attempts to collect a receivable have failed or, if later, by six months from when a customer becomes inactive, the receivable is written-off against the allowance. Management believes that the allowance for doubtful accounts as of March 31, 2006 was adequate. However, actual write-offs could exceed the recorded allowance. The allowance activity was as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Beginning balance	\$ 11.6	\$ 23.3	\$ 31.1
Charged to costs and expenses, net (a)	9.2	5.0	5.2
Write-offs, net (b)	(9.4)	(16.7)	(13.0)
Ending balance	<u>\$ 11.4</u>	<u>\$ 11.6</u>	<u>\$ 23.3</u>

- (a) Includes amounts charged to expense for adjustments to the allowance for doubtful accounts, net of recoveries of wholesale accounts receivable.
- (b) Includes write-offs of retail and wholesale accounts receivable, net of recoveries of retail accounts receivable.

**Inventories** - Inventories are valued at the lower of average cost or market.

**Property, plant and equipment** - Property, plant and equipment are originally recorded at the cost of contracted services, direct labor and materials, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable electric utility properties retired, less salvage value, is charged to accumulated depreciation. The cost of removal is charged against the regulatory liability established through depreciation rates. Annual overhaul costs for the replacement of defined retirement units are capitalized. Generally other costs of overhaul activities and other repairs and maintenance are expensed as they are incurred.

Intangible plant consists primarily of computer software costs that are originally recorded at cost. Accumulated amortization on Intangible plant was \$329.8 million at March 31, 2006 and \$307.6 million at March 31, 2005. Amortization expense on Intangible plant was \$45.5 million for the year ended March 31, 2006 and \$48.5 million for the year ended March 31, 2005. The estimated aggregate amortization on Intangible plant for the next five succeeding 12 month periods ending from March 31, 2007 to March 31, 2011 is \$45.4 million, \$38.9 million, \$31.0 million, \$24.7 million and \$21.8 million. Unamortized computer software costs were \$186.7 million at March 31, 2006 and \$185.1 million at March 31, 2005.

**Depreciation and amortization** - The average depreciable lives of Property, plant and equipment currently in use by category are as follows:

Generation	
Steam plant	20 – 43 years
Hydroelectric plant	14 – 85 years
Other plant	15 – 35 years
Transmission	20 – 70 years
Distribution	44 – 50 years
Intangible plant	5 – 50 years
Other	5 – 30 years

Computer software costs included in Intangible plant are initially assigned a depreciable life of 5 to 10 years.

During the year ended March 31, 2005, PacifiCorp changed the estimated average lives of certain computer software systems to reflect operational plans. This change reduced amortization expense by \$12.9 million annually on existing computer software systems, with an annual impact to net income of approximately \$8.0 million.

Depreciation and amortization are computed by the straight-line method either over the life prescribed by PacifiCorp's various regulatory jurisdictions for regulated assets or over the assets' estimated useful lives. Composite depreciation rates of average depreciable assets on utility Property, plant and equipment (excluding amortization of capital leases) were 3.0% for each of the years ended March 31, 2006, 2005 and 2004.

**Asset impairments** - Long-lived assets to be held and used by PacifiCorp are reviewed for impairment when events or circumstances indicate costs may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144"). The impacts of regulation on cash flows are considered when determining impairment. Impairment losses on long-lived assets are recognized when book values exceed expected undiscounted future cash flows with the impairment measured on a discounted future cash flows basis.

**Allowance for funds used during construction** - The allowance for funds used during construction (the "AFUDC") represents the cost of debt and may also include equity funds used to finance utility property additions during construction. As prescribed by regulatory authorities, the AFUDC is capitalized as a part of the cost of utility property and is recorded in the Consolidated Statements of Income as Interest capitalized. Under regulatory rate practices, PacifiCorp is generally permitted to recover the AFUDC, and a fair return thereon, through its rate base after the related utility property is placed in service.

The composite capitalization rates were 6.5% for the year ended March 31, 2006; 4.5% for the year ended March 31, 2005; and 7.9% for the year ended March 31, 2004. PacifiCorp's AFUDC rates do not exceed the maximum allowable rates determined by regulatory authorities.

**Derivatives** - In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, ("SFAS No. 133"), as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, and SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* ("SFAS No. 149") (collectively "SFAS No. 133"), derivative instruments are measured at fair value and recognized as either assets or liabilities on the Consolidated Balance Sheets, unless they qualify for the exemptions afforded by the standard. Changes in the fair value of derivatives are recognized in earnings during the period of change. Certain long-term derivative contracts have been approved by regulatory authorities for recovery through retail rates. Accordingly, changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS No. 71. Derivative contracts for commodities used in PacifiCorp's normal business operation and that settle by physical delivery, among other criteria, are eligible for the normal purchases and normal sales exemption afforded by SFAS No. 133. These contracts are accounted for under accrual accounting and recorded in Revenues or Energy costs in the Consolidated Statements of Income when the contracts settle.

**Marketable securities** - PacifiCorp accounts for marketable securities, included in Deferred charges and other on PacifiCorp's Consolidated Balance Sheets, in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. PacifiCorp determines the appropriate classification of all marketable securities as held-to-maturity, available-for-sale or trading at the time of purchase and re-evaluates such classification as of each balance sheet date. As shown in Note 5 - Marketable Securities, at March 31, 2006 and 2005, all of PacifiCorp's investments in marketable securities were classified as available-for-sale and were reported at fair value. PacifiCorp uses the specific identification method in computing realized gains and losses on the sale of its available-for-sale securities. Realized gains and losses are included in Other (income) expense. Unrealized gains and losses are reported as a component of Accumulated other comprehensive income (loss). Investments that are in loss positions as of the end of each reporting period are analyzed to determine whether they have experienced a decline in market value that is considered other-than-temporary. An investment will generally be written down to market value if it has a significant unrealized loss for more than nine months. If additional information is available that indicates an investment is other-than-temporarily impaired, it will be written down prior to the nine-month time period. If an

investment has been impaired for more than nine months but available information indicates that the impairment is temporary, the investment will not be written down.

**Amounts held in trust** – PacifiCorp holds certain trusts to fund decommissioning and reclamation activities as described in Note 5 – Marketable Securities and Note 6 – Asset Retirement Obligations and Accrued Environmental Costs. Amounts are also held in trusts that serve as funding vehicles for certain of PacifiCorp’s employee benefits, including the Supplemental Executive Retirement Plan (the “SERP”) as described in Note 17 – Employee Benefits.

**Asset retirement obligations and accrued removal costs** - Effective April 1, 2003, PacifiCorp recognizes the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* (“SFAS No. 143”). The initial recognition of this liability is accompanied by a corresponding increase in Property, plant and equipment. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to Property, plant and equipment) and for accretion of the liability due to the passage of time. Additional depreciation expense is recorded prospectively for any Property, plant and equipment increases. In general, depreciation and accretion expense generated by SFAS No. 143 accounting is recorded as a regulatory asset or liability because such amounts are recoverable in rates. As of March 31, 2006, PacifiCorp adopted Financial Accounting Standards Board (the “FASB”) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143* (“FIN 47”) as described in Note 6 – Asset Retirement Obligations and Accrued Environmental Costs.

For those asset retirement removal costs that do not meet the requirements of SFAS No. 143, PacifiCorp recovers through approved depreciation rates estimated removal costs and accumulates such amounts in Asset retirement removal costs within Regulatory liabilities as described in Note 2 – Accounting for the Effects of Regulation.

**Income taxes** - PacifiCorp uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Prior to the sale of PacifiCorp to MEHC on March 21, 2006, PacifiCorp was a wholly owned subsidiary of PHI. Therefore, it was included in the consolidated income tax return for PHI from April 1, 2003 through March 21, 2006. PacifiCorp currently is an indirect, majority-owned subsidiary of Berkshire Hathaway Inc. and is included in its consolidated income tax return. PacifiCorp’s provision for income taxes has been computed on the basis that it files separate consolidated income tax returns with its subsidiaries.

Historically, PacifiCorp did not recognize deferred taxes on many of the timing differences between book and tax depreciation. In prior years, these benefits were flowed through to the utility customer as prescribed by PacifiCorp’s various regulatory jurisdictions. Deferred income tax liabilities and Regulatory assets have been established for those flow-through tax benefits as shown in Note 2 – Accounting for the Effects of Regulation since PacifiCorp is allowed to recover the increased income tax expense when these differences reverse.

Investment tax credits are deferred and amortized to income over periods prescribed by PacifiCorp’s various regulatory jurisdictions.

PacifiCorp establishes accruals for certain tax contingencies when, despite the belief that its tax return positions are supported, it also believes that certain positions may be challenged and that it is probable those positions may not be fully sustained. PacifiCorp is under continuous examination by the Internal Revenue Service and other tax authorities and accounts for potential losses of tax benefits in accordance with SFAS No. 5, *Accounting for Contingencies* (“SFAS No. 5”). See Note 19 – Income Taxes for further information.

**Stock-based compensation** - As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation* (“SFAS No. 123”), PacifiCorp accounts for its stock-based compensation arrangements, primarily employee stock options, under the intrinsic value recognition and measurement principles of Accounting Principles Board (“APB”) Opinion No. 25, *Accounting for Stock Issued to Employees* (“APB No. 25”), and related interpretations in accounting for employee stock options issued to PacifiCorp employees. Under APB No. 25, because the exercise price of employee

stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recorded if the ultimate number of shares to be awarded is known at the date of the grant. All options currently

accounted for under APB No. 25 were issued in ScottishPower American Depository Shares, as discussed in Note 18 – Stock-Based Compensation. Had PacifiCorp determined compensation cost based on the fair value at the grant date for all stock options vesting in each period under SFAS No. 123, PacifiCorp's Net income would have been reduced to the pro forma amounts below:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Net income as reported	\$ 360.7	\$ 251.7	\$ 248.1
Add: stock-based compensation included in reported net income, net of related tax effects	0.1	3.1	-
Less: stock-based compensation expense using the fair value method, net of related tax effects	(1.4)	(4.3)	(1.1)
Pro forma net income	<u>\$ 359.4</u>	<u>\$ 250.5</u>	<u>\$ 247.0</u>

**Revenue recognition** - Revenue is recognized upon delivery for retail and wholesale electricity sales. Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, which are earned but not yet billed, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The process of calculating the Unbilled revenue estimate consists of three components: quantifying PacifiCorp's total electricity delivered during the month, assigning Unbilled revenues to customer type and valuing the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type. The amount accrued for Unbilled revenues was \$148.2 million at March 31, 2006 and \$143.8 million at March 31, 2005.

**Segment information** - PacifiCorp currently has one segment, which includes the regulated retail and wholesale electric operations.

**New accounting standards -  
SFAS No. 123R**

On April 1, 2006, PacifiCorp adopted SFAS No. 123R, *Share-Based Payment* ("SFAS No. 123R"), a revision of the originally issued SFAS No. 123. SFAS No. 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS No. 123R requires that the cost resulting from all share-based payment transactions be recognized in the financial statements using the fair value method. The intrinsic value method of accounting established by APB No. 25 will no longer be allowed. The adoption of SFAS No. 123R did not have an effect on PacifiCorp's financial position or results of operations as all requisite service has been rendered by employees and the outstanding stock awards are fully vested. For further information see Note 18 – Stock-Based Compensation.

**EITF No. 04-6**

On April 1, 2006, PacifiCorp adopted Emerging Issues Task Force No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry* ("EITF No. 04-6"). EITF No. 04-6 requires that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced (that is, extracted) during the period that the stripping costs are incurred. The adoption of EITF No. 04-6 did not have a material impact on PacifiCorp's consolidated financial position or results of operations.

## Note 2 - Accounting for the Effects of Regulation

Regulated utilities have historically applied the provisions of SFAS No. 71, which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. Accounting under SFAS No. 71 is appropriate as long as (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be collected from customers.

SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from their treatment as allowable costs for rate-making purposes. In addition, the rate action should permit recovery of the specific previously incurred costs rather than provide for expected levels of similar future costs. PacifiCorp records regulatory assets and liabilities based on management's assessment that it is probable that a cost will be recovered (asset) or that an obligation has been incurred (liability). The final outcome, or additional regulatory actions, could change management's assessment in future periods. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future, with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs, PacifiCorp recognizes amounts charged pursuant to such rates as liabilities and takes those amounts to income only when the associated costs are incurred. In applying SFAS No. 71, PacifiCorp must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS No. 71, PacifiCorp capitalizes certain costs as regulatory assets if authorized to recover the costs in future periods.

PacifiCorp continuously evaluates the appropriateness of applying SFAS No. 71 to each of its jurisdictions. At March 31, 2006, PacifiCorp had recorded specifically identified net regulatory assets of \$174.3 million. In the event PacifiCorp stopped applying SFAS No. 71 at March 31, 2006, an after-tax loss of approximately \$108.2 million would be recognized.

PacifiCorp is subject to the jurisdiction of public utility regulatory authorities of each of the states in which it conducts retail electric operations with respect to prices, services, accounting, issuance of securities and other matters. The jurisdictions in which PacifiCorp operates are in various stages of evaluating deregulation. At present, PacifiCorp is subject to cost-based rate-making for its business. PacifiCorp is a "licensee" and a "public utility" as those terms are used in the Federal Power Act and is, therefore, subject to regulation by the Federal Energy Regulatory Commission (the "FERC") as to accounting policies and practices, certain prices and other matters.

Regulatory assets include the following:

(Millions of dollars)	March 31,	
	2006 (a)	2005 (a)
Deferred income taxes (b)	\$ 480.3	\$ 499.9
Minimum pension liability (c)	257.7	280.7
Unamortized issuance expense on retired debt	29.0	34.6
Demand-side resource costs	13.4	25.5
Transition plan - retirement and severance	16.9	24.9
Various other costs	87.0	107.2
Subtotal	884.3	972.8
Derivative contracts (d)	94.7	170.0
Total	<u>\$ 979.0</u>	<u>\$ 1,142.8</u>

- (a) PacifiCorp had regulatory assets not accruing carrying charges of \$952.9 million at March 31, 2006 and \$1,095.6 million at March 31, 2005.
- (b) Represents accelerated income tax benefits previously passed on to ratepayers that will be included in rates concurrently with recognition of the associated income tax expense.
- (c) Represents minimum pension liability offsets proportionate to the amount of pension costs that are

recoverable in rates. Remaining minimum pension liability offsets are included net of tax in Accumulated other comprehensive income (loss).

- (d) Represents net unrealized losses related to derivative contracts included in rates. See Note 3 – Derivative Instruments for further information.

Regulatory liabilities include the following:

(Millions of dollars)	March 31,	
	2006	2005
Asset retirement removal costs (a)	\$ 699.8	\$ 692.1
Deferred income taxes	43.7	44.4
Bonneville Power Administration Regional Exchange Program	23.3	12.6
Various other costs	37.9	56.9
Total	<u>\$ 804.7</u>	<u>\$ 806.0</u>

- (a) Represents removal costs recovered in rates.

PacifiCorp evaluates the recovery of all regulatory assets periodically and as events occur. The evaluation includes the probability of recovery, as well as changes in the regulatory environment. Regulatory and/or legislative action in Utah, Oregon, Wyoming, Washington, Idaho and California may require PacifiCorp to record regulatory asset write-offs and charges for impairment of long-lived assets in future periods. Impairment would be measured in accordance with PacifiCorp's asset impairment policy, as discussed in Note 1 – Summary of Significant Accounting Policies.

### Note 3 - Derivative Instruments

In accordance with SFAS No. 133, PacifiCorp records derivative instruments on the Consolidated Balance Sheets as assets or liabilities measured at estimated fair value, unless they qualify for the exemptions afforded by the standard. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts.

In July 2003, the EITF issued EITF No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as defined in Issue No. 02-3 ("EITF No. 03-11")*, which provides guidance on whether to report realized gains or losses on physically settled derivative contracts not held for trading purposes on a gross or net basis and requires realized gains or losses on derivative contracts that do not settle physically to be reported on a net basis. The adoption of EITF No. 03-11 during the year ended March 31, 2004 resulted in PacifiCorp netting certain contracts that were previously recorded on a gross basis in Wholesale sales and other revenues and Energy costs in the Consolidated Statements of Income. The adoption of EITF No. 03-11 had no impact on PacifiCorp's consolidated Net income and all periods presented are consistent with the requirements of EITF 03-11.

As the FASB continues to issue interpretations, PacifiCorp may change the conclusions that it has reached and, as a result, the accounting treatment and financial statement impact could change in the future.

The accounting treatment for the various classifications of derivative financial instruments is as follows:

**Normal purchases and normal sales** - The contracts that qualify as normal purchases and normal sales are excluded from the requirements of SFAS No. 133. The realized gains and losses on these contracts are reflected in the Consolidated Statements of Income at the contract settlement date.

**Undesignated** - Unrealized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Consolidated Statements of Income as Revenues. Unrealized gains and losses on derivative contracts not held for trading purposes are presented in the Consolidated Statements of Income as Revenues for sales contracts and as Energy costs and Operations and maintenance expense for purchase contracts and financial swaps.

PacifiCorp has the following types of commodity transactions:

**Wholesale electricity purchase and sales contracts** - PacifiCorp makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historical load and forward market and other economic information and experience. Based on these projections, PacifiCorp purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the prevailing market price. This process involves hedging transactions, which include the purchase and sale of firm energy under long-term contracts, forward physical contracts or financial contracts for the purchase and sale of a specified amount of energy at a specified price over a given period of time.

**Natural gas and other fuel purchase contracts** - PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives.

Where PacifiCorp's derivative instruments are subject to a master netting agreement and the criteria of FIN 39, *Offsetting of Amounts Related to Certain Contracts- An Interpretation of APB Opinion No. 10 and FASB Statement No. 105*, are met, PacifiCorp presents its derivative assets and liabilities, as well as accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets.

Unrealized gains and losses on energy sales and purchase contracts are affected by fluctuations in forward prices for electricity and natural gas. The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Consolidated Statements of Income associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates.

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Revenues	\$ 224.4	\$ (330.0)	\$ (29.4)
Operating expenses:			
Energy costs	(131.1)	338.4	35.5
Operations and maintenance	(6.5)	-	-
Total unrealized gain on derivative contracts	<u>\$ 86.8</u>	<u>\$ 8.4</u>	<u>\$ 6.1</u>

The following table shows the changes in the fair value of energy-related contracts subject to the requirements of SFAS No. 133, as amended, from April 1, 2005, to March 31, 2006.

(Millions of dollars)	Net Asset (Liability)		Regulatory Net Asset (Liability) (b)
	Trading	Non-trading	
Fair value of contracts outstanding at March 31, 2005	\$ 0.2	\$ (154.4)	\$ 170.0
Contracts realized or otherwise settled during the period	(0.2)	(115.8)	128.3
Other changes in fair values (a)	0.2	277.9	(203.6)
Fair value of contracts outstanding at March 31, 2006	<u>\$ 0.2</u>	<u>\$ 7.7</u>	<u>\$ 94.7</u>

- (a) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates, including those based on models, on new and existing contracts.
- (b) Net unrealized losses (gains) related to derivative contracts included in rates are recorded as a regulatory net asset (liability).

PacifiCorp bases its forward price curves upon market price quotations when available and bases them on internally developed and commercial models, with internal and external fundamental data inputs, when market quotations are unavailable. Market quotes are obtained from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by PacifiCorp. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be developed. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve (beyond the first six years) is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market such as long-term natural gas prices and expected inflation rates.

Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward price curve. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. The optionality is valued using a modified Black-Scholes model approach or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve.

Standardized derivative contracts that are valued using market quotations, as described above, are classified in the table below as "values based on quoted market prices from third-party sources." All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as "values based on models and other valuation methods."

	Fair Value of Contracts at Period-End				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
(Millions of dollars)					
Trading:					
Values based on quoted market prices from third-party sources	\$ 0.2	\$ -	\$ -	\$ -	\$ 0.2
Non-trading:					
Values based on quoted market prices from third-party sources	\$ 58.7	\$ 49.7	\$ 6.0	\$ 1.2	\$ 115.6
Values based on models and other valuation methods	64.9	82.9	4.9	(260.6)	(107.9)
Total non-trading	\$ 123.6	\$ 132.6	\$ 10.9	\$ (259.4)	\$ 7.7
Regulatory net asset (liability)	\$ (76.2)	\$ (83.4)	\$ (5.5)	\$ 259.8	\$ 94.7

**Weather derivatives** - PacifiCorp currently has a non-exchange traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. Under the agreement, PacifiCorp pays an annual premium in return for the right to make or receive payments if streamflow levels are above or below certain thresholds. PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flow under the contract in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. The net asset (liability) recorded for this contract was \$(2.1) million at March 31, 2006 and \$20.3 million at March 31, 2005 and was included in other current assets (liabilities) in the Consolidated Balance Sheets. PacifiCorp recognized a loss of \$15.6 million for the year ended March 31, 2006; a gain of \$27.9 million for the year ended March 31, 2005; and a gain of \$0.4 million for the year ended March 31, 2004.

#### **Note 4 – Related-Party Transactions**

**Transactions while owned by MEHC** – As discussed in Note 1 – Summary of Significant Accounting Policies, PacifiCorp was acquired by MEHC on March 21, 2006. The following describes PacifiCorp's transactions and balances with unconsolidated related parties while owned by MEHC.

PacifiCorp began participating in a captive insurance program provided by MEHC Insurance Services Ltd. ("MISL"), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts are established based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2007. Prepayments to MISL were \$7.2 million at March 31, 2006. Premium expenses were \$0.2 million for March 21, 2006 through March 31, 2006.

As of March 31, 2006, Amounts due to affiliates - MEHC included \$3.8 million of current income taxes payable to PPW Holdings LLC.

See Note 1 – Summary of Significant Accounting Policies for information related to the transfer of MEHC's 100.0% ownership interest in Intermountain Geothermal Company to PacifiCorp.

**Transactions while owned by ScottishPower** - There were no loans or advances between PacifiCorp and ScottishPower or between PacifiCorp and PHI. Loans from PacifiCorp to ScottishPower or PHI were prohibited under the Public Utility Holding Company Act of 1935 ("PUHCA"), which was repealed effective February 2006. Loans from ScottishPower or PHI to PacifiCorp generally required state regulatory and SEC approval. There were intercompany loan agreements that allowed funds to be lent to PacifiCorp from PacifiCorp Group Holdings Company ("PGHC"), but loans from PacifiCorp to PGHC were prohibited. There were intercompany loan agreements that allowed funds to be lent between PacifiCorp and Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp. PacifiCorp does not maintain a centralized cash or money pool. Therefore, funds of each company were not commingled with funds of any other company.

The tables below detail PacifiCorp's transactions and balances with unconsolidated related parties while owned by ScottishPower.

(Millions of dollars)	March 31, 2006 *	March 31, 2005
Amounts due from former affiliated entities:		
SPUK (a)	\$ -	\$ 0.3
PHI and its subsidiaries (b)	-	36.2
	<u>\$ -</u>	<u>\$ 36.5</u>
Prepayments to former affiliated entities:		
PHI and its subsidiaries (c)	\$ -	\$ 1.5
Amounts due to former affiliated entities:		
SPUK (d)	\$ -	\$ 3.9
Deposits received from former affiliated entities:		
PHI and its subsidiaries (e)	\$ -	\$ 0.3

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Revenues from former affiliated entities:			
PHI and its subsidiaries (e)	\$ 7.8	\$ 5.9	\$ 4.4
Expenses recharged to former affiliated entities:			
SPUK (a)	\$ 6.2	\$ 3.0	\$ 0.7
PHI and its subsidiaries (b)	7.3	9.4	8.0
	<u>\$ 13.5</u>	<u>\$ 12.4</u>	<u>\$ 8.7</u>
Expenses incurred from former affiliated entities:			
SPUK (d)	\$ 18.6	\$ 18.3	\$ 7.8
PHI and its subsidiaries (c)	19.3	17.3	17.0
DIIL (f)	7.0	-	-
	<u>\$ 44.9</u>	<u>\$ 35.6</u>	<u>\$ 24.8</u>
Interest expense to former affiliated entities:			
PHI and its subsidiaries (g)	\$ -	\$ 0.1	\$ 0.2

\* Amounts settled at close of sale to MEHC.

- (a) For the years ended March 31, 2006 and 2005, receivables and expenses included amounts allocated to Scottish Power UK plc ("SPUK"), an indirect subsidiary of ScottishPower, by PacifiCorp for administrative services provided under ScottishPower's affiliated interest cross-charge policy. For the year ended March 31, 2006, expenses also included costs associated with retention agreements and severance benefits reimbursed by SPUK. In addition, PacifiCorp recharged to SPUK payroll costs and related benefits of PacifiCorp employees working on international assignment in the United Kingdom for ScottishPower during the years ended March 31, 2006, 2005 and 2004.
- (b) Amounts shown pertain to activities of PacifiCorp with its former parent PHI and its subsidiaries. Expenses recharged reflect costs for support services to PHI and its subsidiaries. Amounts due from PHI and its subsidiaries included \$33.8 million as of March 31, 2005 of income taxes receivable from PHI. PHI was the tax-paying entity while PacifiCorp was owned by ScottishPower.
- (c) These expenses primarily related to operating lease payments for the West Valley facility, located in Utah and owned by West Valley Leasing Company, LLC ("West Valley"). West Valley is a subsidiary of PPM Energy, Inc. ("PPM"), which is a subsidiary of PHI. The lease is a 15 year operating lease on an electric generation facility. The facility consists of five generating units each with a nameplate rating of 43.4 MW. Certain costs associated with the West Valley lease are prepaid on an annual basis. Lease expense was

\$16.4 million for the year ended March 31, 2006; \$17.1 million for the year ended March 31, 2005; and \$17.0 million for the year ended March 31, 2004. PacifiCorp has an option to terminate the West Valley lease if written notice is provided to West Valley on or before December 1, 2006. If the option to terminate is exercised, the lease would terminate in May 2008. PacifiCorp is committed to future minimum lease payments of \$10.0 million annually for each of the 12 months ending March 31, 2007 and 2008 and \$1.7 million for the two months ending May 31, 2008. These minimum future lease payments reflect the reduction in monthly payments resulting from a March 2006 amendment to the lease terms.

- (d) These liabilities and expenses primarily represented amounts allocated to PacifiCorp by SPUK for administrative services received under the cross-charge policy. Cross-charges from SPUK to PacifiCorp amounted to \$16.7 million for the year ended March 31, 2006 and \$14.9 million for the year ended March 31, 2005. These costs were recorded in Operations and maintenance expense. SPUK also recharged PacifiCorp for payroll costs and related benefits of SPUK employees working on international assignment with PacifiCorp in the United States.
- (e) These revenues and the associated deposits related to wheeling services billed to PPM. PacifiCorp provided these services to PPM pursuant to PacifiCorp's FERC-approved open access transmission tariff, which required PacifiCorp to make transmission services available on a non-discriminatory basis to all interested parties.
- (f) PacifiCorp began participating in a captive insurance program provided by Dornoch International Insurance Limited ("DIIL"), an indirect wholly owned consolidated subsidiary of ScottishPower, in May 2005. DIIL covered all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's policies, as well as overhead distribution and transmission line property damage. PacifiCorp had no equity interest in DIIL and had no obligation to contribute equity or loan funds to DIIL. Premium amounts were established to cover loss claims, administrative expenses and appropriate reserves, but otherwise DIIL was not operated to generate profits.
- (g) Included interest on short-term demand loans made to PacifiCorp by PGHC, in accordance with regulatory authorization.

#### Note 5 – Marketable Securities

PacifiCorp, by contract with Idaho Power, the minority owner of Bridger Coal Company (an indirect subsidiary of PacifiCorp), maintains a trust relating to final reclamation of a leased coal mining property. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. Trust fund assets associated with Bridger Coal Company recorded at fair value included in Deferred charges and other were \$101.9 million at March 31, 2006 and \$92.4 million at March 31, 2005, including the Idaho Power minority-interest portion. Minority interest in Bridger Coal Company was \$49.5 million at March 31, 2006 and \$26.2 million at March 31, 2005. See also Note 6 – Asset Retirement Obligations and Accrued Environmental Costs.

The amortized cost and fair value of reclamation trust securities and other investments included in Deferred charges and other on PacifiCorp's Consolidated Balance Sheets, which are classified as available-for-sale, were as follows:

(Millions of dollars)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
<b>March 31, 2006</b>				
Debt securities	\$ 25.9	\$ 0.2	\$ (0.6)	\$ 25.5
Equity securities	61.7	7.0	(0.7)	68.0
<b>Total</b>	<b>\$ 87.6</b>	<b>\$ 7.2</b>	<b>\$ (1.3)</b>	<b>\$ 93.5</b>
<b>March 31, 2005</b>				
Mutual fund account (a)	\$ 27.0	\$ -	\$ (1.0)	\$ 26.0
Debt securities	25.6	0.4	(0.4)	25.6
Equity securities	60.6	13.2	(1.2)	72.6
<b>Total</b>	<b>\$ 113.2</b>	<b>\$ 13.6</b>	<b>\$ (2.6)</b>	<b>\$ 124.2</b>

- (a) In October 2005, the mutual fund account was transferred to a money market account.

The quoted market price of securities is used to estimate their fair value.

The amortized cost and estimated fair value of debt securities at March 31, 2006 and 2005 by contractual maturities and of equity securities for the same dates are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

(Millions of dollars)	March 31,			
	2006		2005	
	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Debt securities				
Due in one year or less	\$ 0.7	\$ 0.6	\$ 0.7	\$ 0.7
Due after one year through five years	6.5	6.4	5.6	5.6
Due after five years through ten years	9.9	9.8	9.8	9.9
Due after ten years	8.8	8.7	9.5	9.4
Mutual fund account	-	-	27.0	26.0
Equity securities	61.7	68.0	60.6	72.6
Total	<u>\$ 87.6</u>	<u>\$ 93.5</u>	<u>\$ 113.2</u>	<u>\$ 124.2</u>

Proceeds, gross gains and gross losses from realized sales of available-for-sale securities using the specific identification method were as follows for the years ended March 31, 2006, 2005 and 2004:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Proceeds	<u>\$ 123.4</u>	<u>\$ 49.1</u>	<u>\$ 95.8</u>
Gross gains	\$ 16.6	\$ 6.3	\$ 6.5
Gross losses	<u>(2.3)</u>	<u>(2.2)</u>	<u>(3.4)</u>
Net gains	14.3	4.1	3.1
Less net gains included in Regulatory liabilities (a)	<u>(16.6)</u>	<u>(5.6)</u>	<u>(3.2)</u>
Net losses included in Net income	<u>\$ (2.3)</u>	<u>\$ (1.5)</u>	<u>\$ (0.1)</u>

- (a) Realized gains and losses on the Bridger Coal Company reclamation trust described above are recorded as a regulatory liability in accordance with the prescribed regulatory treatment.

#### Note 6 – Asset Retirement Obligations and Accrued Environmental Costs

**Asset Retirement Obligations** - PacifiCorp records asset retirement obligations for long-lived physical assets that qualify as legal obligations under SFAS No. 143. PacifiCorp estimates its asset retirement obligation liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. PacifiCorp then records an asset retirement obligation asset associated with the liability. The asset retirement obligation assets are depreciated over their expected lives and the asset retirement obligation liabilities are accreted to the projected spending date. Changes in estimates could occur due to plan revisions, changes in estimated costs and changes in timing of the performance of reclamation activities. In addition, PacifiCorp records removal costs as a part of depreciation expense in accordance with regulatory accounting requirements described in Note 2 – Accounting for the Effects of Regulation. Since asset retirement costs are recovered through the ratemaking process, PacifiCorp records a regulatory asset or regulatory liability on the

Consolidated Balance Sheets to account for the difference between asset retirement costs as currently approved in rates and costs under SFAS No. 143.

PacifiCorp does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. PacifiCorp has asset retirement obligations associated with its transmission and distribution systems and certain coal mines. However, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Consolidated Financial Statements.

In March 2005, the FASB issued FIN 47. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the fair value of the liability can be reasonably estimated. Upon adoption of FIN 47 at March 31, 2006, PacifiCorp recorded an asset retirement obligation liability at a net present value of \$22.7 million. PacifiCorp also increased net depreciable assets by \$1.8 million, reclassified \$13.5 million of costs accrued for retirement removals from regulatory liabilities to asset retirement obligation liabilities, increased regulatory liabilities by \$0.4 million and increased regulatory assets by \$7.8 million for the difference between retirement costs approved by regulators and obligations under FIN 47.

The pro forma total asset retirement obligation liability balances that would have been reported assuming FIN 47 had been adopted on April 1, 2004, rather than March 31, 2006, are as follows:

(Millions of dollars)

Pro forma asset retirement obligation liability at April 1, 2004	\$215.8
Pro forma asset retirement obligation liability at March 31, 2005	\$222.1

Due to regulatory accounting treatment, the adoption of FIN 47 would have no material impact on net income for the pro forma periods listed above and had no impact on PacifiCorp's reported cash flows.

The following table describes the changes to PacifiCorp's asset retirement obligation liability for the years ended March 31, 2006 and 2005:

(Millions of dollars)	March 31, 2006	March 31, 2005
Liability recognized at beginning of period	\$ 199.6	\$ 193.5
Liabilities incurred (a)	25.2	1.4
Liabilities settled (b)	(10.4)	(13.0)
Revisions in cash flow (c)	(11.2)	8.9
Accretion expense	8.9	8.8
Asset retirement obligation	212.1	199.6
Less current portion (d)	7.0	17.8
Long-term asset retirement obligation at end of period (e)	<u>\$ 205.1</u>	<u>\$ 181.8</u>

- (a) Relates primarily to the adoption of FIN 47 at March 31, 2006.
- (b) Relates primarily to ongoing reclamation work at the Glenrock coal mine.
- (c) Results from changes in the timing and amounts of estimated cash flows for certain plant reclamation.
- (d) Amount included in Other current liabilities on the Consolidated Balance Sheets.
- (e) Amount included in Deferred credits - other on the Consolidated Balance Sheets.

PacifiCorp had trust fund assets recorded at fair value included in Deferred charges and other of \$103.0 million at March 31, 2006 and \$93.4 million at March 31, 2005 relating to mine and plant reclamation, including the minority-interest joint-owner portions.

**Accrued Environmental Costs** – PacifiCorp's policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations,

advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement. PacifiCorp hires external consultants from time to time to conduct studies in order to establish reserves for various site environmental remediation costs. PacifiCorp is subject to cost-sharing agreements with other potentially responsible parties based on decrees, orders and other legal agreements. In these circumstances, PacifiCorp assesses the financial capability of other potentially responsible parties and the reasonableness of PacifiCorp's apportionment. These agreements may affect the range of potential loss. Additionally, PacifiCorp may benefit from excess insurance policies that may cover some of the cleanup costs if costs incurred exceed certain amounts.

PacifiCorp assesses its potential obligations to perform environmental remediation on an ongoing basis. As a result of studies performed during the year ended March 31, 2006, PacifiCorp increased its reserve by \$9.7 million to reflect its most likely estimate for probable liabilities. Remediation costs that are fixed and determinable have been discounted to their present value using credit-adjusted, risk-free discount rates based on the expected future annual borrowing rates of PacifiCorp. The liability recorded was \$38.5 million at March 31, 2006 and \$33.3 million at March 31, 2005 and is included as part of Deferred credits - other. The March 31, 2006 recorded liability included \$18.1 million of discounted liabilities. Had none of the liabilities included in the \$38.5 million balance recorded at March 31, 2006 been discounted, the total would have been \$40.7 million. The expected payments for each of the five 12 month periods ending March 31 and thereafter are as follows: \$5.4 million in 2007, \$3.9 million in 2008, \$2.4 million in 2009, \$1.5 million in 2010, \$1.2 million in 2011 and \$26.3 million thereafter.

It is possible that future findings or changes in estimates could require that additional amounts be accrued. Should current circumstances change, it is possible that PacifiCorp could incur an additional undiscounted obligation of up to approximately \$53.1 million relating to existing sites. However, management believes that completion or resolution of these matters will have no material adverse effect on PacifiCorp's consolidated financial position or results of operations.

#### **Note 7 - Notes Payable and Commercial Paper**

Amounts outstanding under PacifiCorp's short-term notes payable and commercial paper arrangements were as follows:

(Millions of dollars)	Balance	Average Interest Rate
March 31, 2006	\$ 184.4	4.8 %
March 31, 2005	468.8	2.9

#### **Revolving Credit Agreement**

PacifiCorp amended and restated its existing \$800.0 million committed bank revolving credit agreement in August 2005. Changes included an increase to 65.0% in the covenant not to exceed a specified debt-to-capitalization percentage, extension of the termination date to August 29, 2010 and exclusion of the acquisition of PacifiCorp by MEHC as an event of default under the agreement. As of March 31, 2006, PacifiCorp's revolving credit agreement was fully available and had no borrowings outstanding. The interest on advances under this facility is generally based on the London Interbank Offered Rate (LIBOR) plus a margin that varies based on PacifiCorp's credit ratings. This facility supports PacifiCorp's commercial paper program and \$38.1 million of variable rate pollution control revenue bonds.

PacifiCorp's revolving credit agreement contains customary covenants and default provisions and PacifiCorp monitors these covenants on a regular basis. As of March 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit agreement.

## Note 8 - Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows:

(Millions of dollars)	March 31,			
	2006		2005	
	Amount	Average Interest Rate	Amount	Average Interest Rate
<u>First mortgage bonds</u>				
4.3% to 8.8%, due through 2011	\$ 901.7	6.0 %	\$ 1,171.4	6.2 %
5.0% to 9.2%, due 2012 to 2016	1,040.4	6.5	1,040.4	6.5
8.5% to 8.6%, due 2017 to 2021	5.0	8.5	5.0	8.5
6.7% to 8.5%, due 2022 to 2026	424.0	7.4	424.0	7.4
5.3 % to 7.7%, due 2032 to 2036	800.0	6.3	500.0	7.0
Unamortized discount	(4.7)		(4.3)	
<u>Guaranty of pollution-control revenue bonds</u>				
Variable rates, due 2014 (a) (b)	40.7	3.1	40.7	2.3
Variable rates, due 2014 to 2026 (b)	325.2	3.2	325.2	2.3
Variable rates, due 2025 (a) (b)	175.8	3.2	175.8	2.3
3.4% to 5.7%, due 2014 to 2026 (a)	184.0	4.5	184.0	4.5
6.2%, due 2031	12.7	6.2	12.7	6.2
Unamortized discount	(0.5)		(0.5)	
Funds held by trustees	(2.2)		(2.1)	
<u>Capital lease obligations</u>				
10.4% to 14.8%, due through 2035	35.8	11.7	26.6	11.9
Total	3,937.9		3,898.9	
Less current maturities	(216.9)		(269.9)	
Total	<u>\$ 3,721.0</u>		<u>\$ 3,629.0</u>	

- (a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution-control revenue bonds.
- (b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of PacifiCorp may be issued in amounts limited by PacifiCorp's property, earnings and other provisions of the mortgage indenture. Approximately \$13.8 billion of the eligible assets (based on original cost) of PacifiCorp are subject to the lien of the mortgage.

Approximately \$2.3 billion of first mortgage bonds were redeemable at PacifiCorp's option at March 31, 2006 at redemption prices dependent upon United States Treasury yields. Approximately \$541.7 million of variable-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par at March 31, 2006. Approximately \$71.2 million of fixed-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par at March 31, 2006. The remaining long-term debt was not redeemable at March 31, 2006.

In September 2005, the SEC declared effective PacifiCorp's shelf registration statement covering \$700.0 million of future first mortgage bond and unsecured debt issuances. PacifiCorp has not yet issued any of the securities covered by this registration statement.

In June 2005, PacifiCorp issued \$300.0 million of its 5.25% Series of First Mortgage Bonds due June 15, 2035. PacifiCorp used the proceeds for the reduction of short-term debt, including the short-term debt used in December 2004 to redeem its 8.625% Series of First Mortgage Bonds due December 13, 2024 totaling \$20.0 million.

In March 2005, the maturity dates were extended to December 1, 2020 for three series of variable-rate pollution-control revenue bonds totaling \$38.1 million.

PacifiCorp leases equipment and real estate in various states in which it does business under long-term agreements, extending through March 2035, which are classified as capital leases. These capital leases are payable in monthly installments allocated between principal and imputed interest rates ranging from 10.4% to 14.8%.

In April 2005, PacifiCorp entered into a 30-year transportation service agreement with Questar Pipeline Company for the right to use a newly constructed pipeline facility with a majority of the output designated to provide natural gas to the Currant Creek Power Plant. This agreement qualifies as a capital lease with an initial net present value lease obligation of \$12.4 million at an imputed interest rate of 11.3%.

The annual maturities of long-term debt and capital lease obligations for the 12 months ending March 31 are:

(Millions of dollars)	Long-term Debt	Capital Lease Obligations	Total
2007	\$ 216.3	\$ 4.8	\$ 221.1
2008	119.9	4.8	124.7
2009	412.4	4.8	417.2
2010	138.5	5.0	143.5
2011	14.6	4.9	19.5
Thereafter	3,007.8	63.8	3,071.6
	3,909.5	88.1	3,997.6
Unamortized discount	(5.2)	-	(5.2)
Funds held by trustee	(2.2)	-	(2.2)
Amounts representing interest	-	(52.3)	(52.3)
	<u>\$ 3,902.1</u>	<u>\$ 35.8</u>	<u>\$ 3,937.9</u>

PacifiCorp made interest payments, net of capitalized interest, of \$240.3 million for the year ended March 31, 2006; \$220.4 million for the year ended March 31, 2005; and \$236.7 million for the year ended March 31, 2004.

At March 31, 2006, PacifiCorp had \$517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately \$40.5 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of March 31, 2006 and expire periodically through the 12 months ending March 31, 2011.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants to those contained in PacifiCorp's revolving credit agreement, although the maximum permitted debt-to-capitalization ratio for one of the standby bond purchase agreements was 60.0% as of March 31, 2006 and was amended in May 2006 to now permit a maximum ratio of 65.0%. See Note 7 – Notes Payable and Commercial Paper for further information. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and as of March 31, 2006, PacifiCorp was in compliance with the covenants of these agreements.

#### Note 9 – Preferred Stock Subject to Mandatory Redemption

PacifiCorp's Preferred stock subject to mandatory redemption was as follows:

(Thousands of shares, millions of dollars) Series	March 31, 2006		March 31, 2005	
	Shares	Amount	Shares	Amount
Preferred stock subject to mandatory redemption				
\$7.48 No Par Serial Preferred, \$100 stated value, 16,000 shares authorized	<u>450</u>	<u>\$ 45.0</u>	<u>525</u>	<u>\$ 52.5</u>

PacifiCorp has mandatory redemption requirements on 37,500 shares of the \$7.48 series Preferred stock on June 15, 2006, with a non-cumulative option to redeem an additional 37,500 shares on June 15, 2006, at \$100.0 per share, plus accrued and unpaid dividends to the date of such redemption. All outstanding shares on June 15, 2007 are subject to mandatory redemption. Holders of Preferred stock subject to mandatory redemption are entitled to certain voting rights and may have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments. PacifiCorp redeemed \$7.5 million of Preferred stock subject to mandatory and optional redemption during each of the years ended March 31, 2006, 2005 and 2004.

PacifiCorp had \$0.8 million at March 31, 2006 and \$1.0 million at March 31, 2005 in dividends declared but unpaid on Preferred stock subject to mandatory redemption that were included in Interest payable.

#### **Note 10 - Commitments and Contingencies**

PacifiCorp follows SFAS No. 5, to determine accounting and disclosure requirements for contingencies. PacifiCorp operates in a highly regulated environment. Governmental bodies such as the FERC, state regulatory commissions, the SEC, the Internal Revenue Service, the Department of Labor, the United States Environmental Protection Agency (the "EPA") and others have authority over various aspects of PacifiCorp's business operations and public reporting. Reserves are established when required in management's judgment, and disclosures regarding litigation, assessments and creditworthiness of customers or counterparties, among others, are made when appropriate. The evaluation of these contingencies is performed by various specialists inside and outside of PacifiCorp.

From time to time, PacifiCorp is also a party to various legal claims, actions, complaints and disputes, certain of which involve material amounts. PacifiCorp has recorded \$6.7 million in reserves as of March 31, 2006 related to various outstanding legal actions and disputes, excluding those discussed below. This amount represents PacifiCorp's best estimate of probable losses related to these matters. PacifiCorp currently believes that disposition of these matters will not have a material adverse effect on PacifiCorp's consolidated financial position, results of operations or liquidity.

**Environmental matters** - PacifiCorp is subject to numerous environmental laws, including the federal Clean Air Act and various state air quality laws; the Endangered Species Act, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws could potentially impact future operations. Environmental contingencies identified at March 31, 2006 principally consist of air quality matters. Pending or proposed air regulations will require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxides and other pollutants below current levels. These reductions will be required to address regional haze programs, mercury emissions regulations and possible re-interpretations and changes to the federal Clean Air Act. In the future, PacifiCorp expects to incur significant costs to comply with various stricter air emissions requirements. These potential costs are expected to consist primarily of capital expenditures. PacifiCorp expects these costs would be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated results of operations. See also Note 6 – Asset Retirement Obligations and Accrued Environmental Costs.

**Hydroelectric relicensing** - PacifiCorp's hydroelectric portfolio consists of 51 plants with an aggregate plant net capability of 1,159.4 MW. The FERC regulates 93.9% of the installed capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing under the Federal Power Act. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred \$70.3 million in costs as of March 31, 2006 for ongoing hydroelectric relicensing, which are reflected in Construction work-in-progress on the Consolidated Balance Sheet. PacifiCorp expects that these and future costs will be included in rates and, as such, will not have a material adverse impact on PacifiCorp's consolidated financial position or results of operations.

In October 2005, the new FERC license for the North Umpqua hydroelectric project became final under the terms of the North Umpqua Settlement Agreement. Prior to this date, the license had been effective, but not final, because environmental groups had challenged its legality before the FERC and in federal court. In September 2005, the Ninth Circuit Court of Appeals issued an order upholding the new license. Since the Court's order was not appealed within the allowed time, all legal challenges of the FERC license order have been exhausted and the license is final for purposes of recording liabilities. PacifiCorp is committed, over the 35-year life of the license, to fund approximately \$48.4 million for environmental mitigation and enhancement projects. As a result of the license becoming final, PacifiCorp recorded additional liabilities and intangible assets in October 2005 amounting to a present value of \$11.2 million. At March 31, 2006, the liability recorded for all North Umpqua obligations amounted to a present value of \$21.8 million.

#### **FERC Issues**

**California Refund Case** - PacifiCorp is a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices. PacifiCorp has a reserve of \$17.7 million for these potential refunds. PacifiCorp's ultimate exposure to refunds is dependent upon any order issued by the FERC in this proceeding. In addition, beginning in summer 2000, California market conditions resulted in defaults of amounts due to PacifiCorp from certain counterparties resulting from transactions with the California Independent System Operator and California Power Exchange. PacifiCorp has reserved \$5.0 million for these receivables.

**FERC Market Power Analysis** - Pursuant to the FERC's orders granting PacifiCorp authority to sell capacity and energy at market-based rates, PacifiCorp and certain of its former affiliates had been required to submit a joint market power analysis every three years. Under the FERC's current policy, applicants must demonstrate that they do not possess market power in order to charge market-based rates for sales of wholesale energy and capacity in the applicants' control areas. An analysis demonstrating an applicant's passage of certain threshold screens for assessing generation market power establishes a rebuttable presumption that the applicant does not possess generation market power, while failure to pass any screen creates a rebuttable presumption that the applicant has generation market power. In February 2005, PacifiCorp submitted a joint triennial market power analysis in compliance with the FERC's requirements. The analysis indicated that PacifiCorp failed to pass one of the generation market power screens in PacifiCorp's eastern control area and in Idaho Power Company's control area. In May 2005, the FERC issued an order instituting a proceeding pursuant to section 206 of the Federal Power Act to determine whether PacifiCorp may continue to charge market-based rates for sales of wholesale energy and capacity. Under the terms of the order, PacifiCorp and its formerly affiliated co-applicants were required to submit additional information and analysis to the FERC within 60 days to rebut the presumption that PacifiCorp has generation market power. In June and July 2005, PacifiCorp filed additional analysis in response to the FERC's May 2005 order. In January 2006, the FERC requested PacifiCorp to amend its previous filings with additional analysis, which was filed in March 2006. If the FERC ultimately finds that PacifiCorp has market power, PacifiCorp will be required to implement measures to mitigate any exercise of market power, which may result in decreased revenues and/or increased operating expenses. PacifiCorp believes the outcome of this proceeding will not have a material impact on its consolidated financial position or results of operations.

#### **Note 11 – Guarantees and Other Commitments**

##### **Guarantees**

PacifiCorp is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"). FIN 45 requires disclosure of certain direct and indirect guarantees.

The following represent the indemnification obligations of PacifiCorp as of March 31, 2006 and 2005.

PacifiCorp has made certain commitments related to the decommissioning or reclamation of certain jointly owned facilities and mine sites. The decommissioning guarantees require PacifiCorp to pay a proportionate share of the decommissioning costs based upon percentage of ownership. The mine reclamation obligations require PacifiCorp to pay the mining entity a proportionate share of the mine's reclamation costs based on the amount of coal

purchased by PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp has recorded its estimated share of the decommissioning and reclamation obligations as either an asset retirement obligation, regulatory liability or other liability.

In connection with the sale of PacifiCorp's Montana service territory, PacifiCorp entered into a purchase and sale agreement with Flathead Electric Cooperative in October 1998. Under the agreement, PacifiCorp indemnified Flathead Electric Cooperative for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of \$10.1 million until October 2008 and a cap of \$5.1 million thereafter (less expended costs to date). Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

From time to time, PacifiCorp executes contracts that include indemnities typical for the underlying transactions, which are related to sales of businesses, property, plant and equipment, and service territories. These indemnities might include any of the following matters: privacy rights; governmental regulations and employment-related issues; commercial contractual relationships; financial reports; tax-related issues; securities laws; and environmental-related issues. Performance under these indemnities generally would be triggered by breach of representations and warranties in the contract. PacifiCorp regularly evaluates the probability of having to incur costs under the indemnities and appropriately accrues for expected losses that are probable and estimable. Some of these indemnities may not limit potential liability; therefore, PacifiCorp is unable to estimate a maximum potential amount of future payments that could result from claims made under these indemnities. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote.

#### **Unconditional Purchase Obligations**

(Millions of dollars)	Payments due during the 12 months ending March 31,						Total
	2007	2008	2009	2010	2011	Thereafter	
Construction	\$ 111.4	\$ 33.2	\$ -	\$ -	\$ -	\$ -	\$ 144.6
Operating leases	15.0	15.3	2.9	2.1	2.1	8.8	46.2
Purchased electricity	756.3	426.7	284.1	290.6	258.0	2,146.7	4,162.4
Transmission	45.7	39.5	37.7	35.3	36.8	503.3	698.3
Fuel	516.8	600.5	522.5	452.7	339.8	1,931.5	4,363.8
Other	52.6	61.0	59.5	53.6	53.4	837.0	1,117.1
Total commitments	<u>\$ 1,497.8</u>	<u>\$ 1,176.2</u>	<u>\$ 906.7</u>	<u>\$ 834.3</u>	<u>\$ 690.1</u>	<u>\$ 5,427.3</u>	<u>\$ 10,532.4</u>

**Construction** - PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. At March 31, 2006, PacifiCorp had estimated long-term unconditional purchase obligations for construction of the new Lake Side Power Plant.

**Operating leases** - PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the 12 months ended March 31, 2013. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Excluded from the operating lease payments above are any power purchase agreements that meet the definition of an operating lease.

Net rent expense was \$28.8 million for the year ended March 31, 2006; \$26.1 million for the year ended March 31, 2005; and \$29.4 million for the year ended March 31, 2004.

Minimum non-cancelable sublease rent payments expected to be received through the 12 months ended March 31, 2013 total \$6.8 million.

**Purchased electricity** - As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and/or exchange agreements. Included in the purchased electricity payments above are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project operating expenses and debt service. These costs are included in Energy costs in the Consolidated Statements of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced.

At March 31, 2006, PacifiCorp's share of long-term arrangements with public utility districts was as follows:

(Millions of dollars)

<u>Generating Facility</u>	<u>Year Contract Expires</u>	<u>Capacity (MW)</u>	<u>Percentage of Output</u>	<u>Annual Costs (a)</u>
Wanapum	2009	194.1	18.7 %	\$ 6.6
Rocky Reach	2011	67.8	5.3	3.6
Priest Rapids	2045	61.0	6.5	2.0
Wells	2018	58.3	6.9	2.1
Total		<u>381.2</u>		<u>\$ 14.3</u>

(a) Includes debt service totaling \$7.0 million.

PacifiCorp's minimum debt service and estimated operating obligations included in purchased electricity above for the 12 months ending March 31 are as follows:

<u>(Millions of dollars)</u>	<u>Minimum Debt Service</u>	<u>Operating Obligations</u>
2007	\$ 9.3	\$ 8.3
2008	9.3	8.4
2009	9.3	8.6
2010	4.7	4.8
2011	4.7	4.9
Thereafter	<u>55.5</u>	<u>84.3</u>
	<u>\$ 92.8</u>	<u>\$ 119.3</u>

PacifiCorp has a 4.0% entitlement to the generation of the Intermountain Power Project, located in central Utah, through a power purchase agreement. PacifiCorp and the City of Los Angeles have agreed that the City of Los Angeles will purchase capacity and energy from PacifiCorp's 4.0% entitlement of the Intermountain Power Project at a price equivalent to 4.0% of the expenses and debt service of the project.

**Fuel** - PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

**Other** - Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions. PacifiCorp has such commitments related to legal or contractual asset retirement obligations, environmental obligations, hydroelectric obligations, equipment maintenance and various other service and maintenance agreements.

### **Resource Management**

PacifiCorp, as a public utility and a franchise supplier, has an obligation to manage resources to supply its customers. Rates charged to most customers are tariff rates authorized by regulatory agencies as discussed in Note 2 – Accounting for the Effects of Regulation.

### **Note 12 - Jointly Owned Facilities**

At March 31, 2006, PacifiCorp's share in jointly owned facilities was as follows:

(Millions of dollars)	PacifiCorp Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work-in- Progress
Jim Bridger Nos. 1 - 4 (a)	66.7 %	\$ 922.2	\$ 467.6	\$ 18.3
Wyodak	80.0	308.8	165.9	14.8
Hunter No. 1	93.8	307.7	142.5	1.8
Colstrip Nos. 3 and 4 (a)	10.0	239.2	116.2	1.5
Hunter No. 2	60.3	212.2	99.4	8.1
Hermiston (b)	50.0	167.0	38.9	1.6
Craig Station Nos. 1 and 2	19.3	165.3	71.3	0.7
Hayden Station No. 1	24.5	41.1	18.6	1.0
Foot Creek	78.8	36.3	10.4	-
Hayden Station No. 2	12.6	26.4	12.8	0.3
Trojan (c)	2.5	-	-	-
Other transmission and distribution plants	Various	78.6	21.2	-
Unallocated acquisition adjustments (d)		157.2	75.8	-
Total		<u>\$ 2,662.0</u>	<u>\$ 1,240.6</u>	<u>\$ 48.1</u>

- (a) Includes kilovolt lines and substations.
- (b) Additionally, PacifiCorp has contracted to purchase the remaining 50.0% of the output of the Hermiston Plant. See Note 13 – Consolidation of Variable-Interest Entities.
- (c) The Trojan Plant was closed in 1993 and PacifiCorp is allowed recovery of costs associated with the plant over the remaining life of the original license. Plant, inventory, fuel and decommissioning costs totaling \$8.1 million relating to the Trojan Plant were included in regulatory assets at March 31, 2006.
- (d) Represents the excess of the costs of the acquired interests in purchased facilities over their original net book values.

Under the joint ownership agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. PacifiCorp's portion is recorded in its applicable construction work-in-progress, operations, maintenance and tax accounts, which is consistent with wholly owned plants.

### **Note 13 – Consolidation of Variable-Interest Entities**

In December 2003, the FASB issued revised FIN 46, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51* ("FIN 46R"), which requires existing unconsolidated variable-interest entities ("VIEs") to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. FIN 46R was adopted as of January 1, 2004 and resulted in disclosures describing identifiable variable interests.

#### **VIE's Required to be Consolidated**

PacifiCorp holds an undivided interest in 50.0% of the 474-MW Hermiston Plant (see Note 12 – Jointly Owned Facilities), procures 100.0% of the fuel input into the plant and subsequently receives 100.0% of the generated electricity, 50.0% of which is acquired through a long-term purchase power agreement. As a result, PacifiCorp holds a variable interest in the joint owner of the remaining 50.0% of the plant and is the primary beneficiary.

However, upon adoption of FIN 46R, PacifiCorp was unable to obtain the information necessary to consolidate the entity, because the entity did not agree to supply the information due to the lack of a contractual obligation to do so. PacifiCorp continues to request from the entity the information necessary to perform the consolidation; however, no information has yet been provided by the entity. Electricity purchased from the joint owner was \$35.2 million during the year ended March 31, 2006; \$34.8 million during the year ended March 31, 2005; and \$33.7 million during the year ended March 31, 2004. The entity is operated by the equity owners, and PacifiCorp has no risk of loss in relation to the entity in the event of a disaster.

#### Significant Variable-Interests in VIE's not Required to be Consolidated

As discussed in Note 4 – Related-Party Transactions, PacifiCorp leases the West Valley facility from a former affiliate under an operating lease that contains purchase options at specified prices. Although the purchase options are variable-interests in West Valley, PacifiCorp is not the primary beneficiary of the entity. PacifiCorp's exposure to loss under the operating lease is negligible.

PacifiCorp is a party to certain operating and coal purchase agreements with Trapper Mining, Inc. that create a variable interest under the provisions of FIN 46R. Trapper Mining, Inc. owns and operates the Trapper Mine near Craig, Colorado, and produces 100.0% of its output for the benefit of the Craig Power Plant. PacifiCorp has a 21.4% equity interest in Trapper Mining, Inc. and also holds a 19.3% undivided interest in the Craig Power Plant as disclosed in Note 12 – Jointly Owned Facilities. Since each equity investor in Trapper Mining, Inc. also holds a similar interest in the Craig Power Plant, and since none of the joint owners have more than a 50.0% interest in the Craig Power Plant or Trapper Mining, Inc., none of the joint owners are required to consolidate Trapper Mining, Inc. Accordingly, PacifiCorp will continue to account for its interest in Trapper Mining, Inc. via the equity method under APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, as in prior periods.

#### Note 14 – Preferred Stock

PacifiCorp's Preferred stock was as follows:

(Thousands of shares, millions of dollars, except per share amounts)	Redemption	March 31, 2006		March 31, 2005	
Series	Price Per Share	Shares	Amount	Shares	Amount
Preferred stock not subject to mandatory redemption					
Serial Preferred, \$100 stated value, 3,500 shares authorized					
4.52 %	\$ 103.5	2	\$ 0.2	2	\$ 0.2
4.56	102.3	85	8.4	85	8.4
4.72	103.5	70	6.9	70	6.9
5.00	100.0	42	4.2	42	4.2
5.40	101.0	66	6.6	66	6.6
6.00	Non-redeemable	6	0.6	6	0.6
7.00	Non-redeemable	18	1.8	18	1.8
5% Preferred, \$100 stated value, 127 shares authorized					
	110.0	126	12.6	126	12.6
		415	\$ 41.3	415	\$ 41.3

Generally, Preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon voluntary liquidation, all Preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all Preferred stock is entitled to stated value plus accrued dividends. Any premium paid on redemptions of Preferred stock is capitalized, and recovery is sought through future rates. Dividends on all Preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

PacifiCorp had \$0.5 million at both March 31, 2006 and March 31, 2005 in dividends declared but unpaid on Preferred stock. The shares and amounts outstanding for each series of Preferred stock not subject to mandatory redemption were unchanged from March 31, 2004 through March 31, 2006.

#### **Note 15 - Common Shareholder's Equity**

**Common Shareholder's Equity** - PacifiCorp has one class of common stock with no par value. A total of 750,000,000 shares were authorized and 357,060,915 shares were issued and outstanding at March 31, 2006 and 312,176,089 shares were issued and outstanding at March 31, 2005. During the year ended March 31, 2006, PacifiCorp issued 44,884,826 shares of its common stock to PHI, its former parent company, at a total price of \$484.7 million. The proceeds from the sale of the shares were used to repay short-term debt.

On March 20, 2006, immediately prior to the closing of PacifiCorp's sale to MEHC, PacifiCorp paid a dividend on common stock, at that time held by PHI, in the aggregate amount of \$16.8 million. The dividend was reduced pursuant to Amendment No. 1 to the Stock Purchase Agreement among MEHC, ScottishPower and PHI executed on the date of the transaction's closing from the \$56.6 million aggregate amount originally declared by the PacifiCorp Board of Directors on January 27, 2006.

In the past, to the extent PacifiCorp did not reimburse ScottishPower for stock-based compensation awarded under ScottishPower plans, such amounts increased the value of PacifiCorp's common shareholder's capital.

**Common Dividend Restrictions** - MEHC is the sole indirect shareholder of PacifiCorp's common stock. The state regulatory orders that authorized the acquisition of PacifiCorp by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

In addition, PacifiCorp is restricted from making any distributions to PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of March 31, 2006, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to maximum debt-to-total capitalization levels under various debt agreements.

#### **Note 16 - Fair Value of Financial Instruments**

(Millions of dollars)	March 31, 2006		March 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (a)	\$ 3,902.1	\$ 4,091.4	\$ 3,872.3	\$ 4,209.5
Preferred stock subject to mandatory redemption	45.0	46.3	52.5	56.0

(a) Includes long-term debt classified as currently maturing, less capital lease obligations.

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments.

The fair value of PacifiCorp's long-term debt, current maturities of long-term debt and redeemable preferred stock has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities.

#### **Note 17 - Employee Benefits**

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides health care and life insurance benefits through various plans for eligible retirees. The measurement date for plan assets and obligations is December 31 of each year.

As a result of the sale of PacifiCorp to MEHC, plan participants that were employees or retirees of certain ScottishPower affiliates and a former PacifiCorp mining subsidiary ceased to participate in PacifiCorp's plans. This separation resulted in a net \$3.5 million reduction in Common shareholder's capital.

#### **Pension Plans**

PacifiCorp's pension plans include the PacifiCorp Retirement Plan (the "Retirement Plan"), the SERP and a joint trust plan to which PacifiCorp contributes on behalf of certain bargaining unit employees of IBEW Local 57. Benefits under the Retirement Plan are based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from social security. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes.

Components of the net periodic pension benefit cost (income) are summarized as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Service cost (a)	\$ 32.2	\$ 25.9	\$ 25.8
Interest cost	74.4	73.8	73.9
Expected return on plan assets (b)	(76.9)	(77.7)	(80.7)
Amortization of unrecognized net transition obligation	8.4	8.4	8.4
Amortization of unrecognized prior service cost	1.2	1.4	1.5
Amortization of unrecognized loss	21.5	8.5	-
Cost of termination benefits	3.0	-	-
Net periodic pension benefit cost	<u>\$ 63.8</u>	<u>\$ 40.3</u>	<u>\$ 28.9</u>

- (a) Includes contributions to the PacifiCorp/IBEW Local 57 Retirement Trust Fund of \$1.4 million for the year ended March 31, 2006; no contributions for the year ended March 31, 2005; and contributions of \$5.6 million for the year ended March 31, 2004.
- (b) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets and is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur.

The weighted-average rates assumed in the actuarial calculations used to determine the net periodic benefit costs for the pension and postretirement benefit plans were as follows:

	Years Ended March 31,		
	2006	2005	2004
Discount rate	5.75 %	6.25 %	6.75 %
Expected long-term rate of return on assets	8.75	8.75	8.75
Rate of increase in compensation levels	4.00	4.00	4.00

PacifiCorp determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

The weighted-average rates assumed in the actuarial calculations used to determine benefit obligations for the pension and postretirement benefit plans were as follows:

	March 31,		
	2006	2005	2004
Discount rate	5.75 %	5.75 %	6.25 %
Rate of increase in compensation levels	4.00	4.00	4.00

The change in the projected benefit obligation, change in plan assets and funded status of the pension plans are as follows:

(Millions of dollars)	March 31,	
	2006	2005
<u>Change in projected benefit obligation</u>		
Projected benefit obligation - beginning of year	\$ 1,338.1	\$ 1,229.8
Service cost	30.8	25.9
Interest cost	74.4	73.8
Plan amendments	2.9	1.0
Cost of termination benefits	3.0	-
Separation of former participants	(44.3)	-
Actuarial loss	22.9	86.8
Benefits paid	(84.1)	(79.1)
Transfers	(1.5)	(0.1)
Projected benefit obligation - end of year	<u>\$ 1,342.2</u>	<u>\$ 1,338.1</u>
<u>Change in plan assets</u>		
Plan assets at fair value - beginning of year	\$ 806.5	\$ 733.2
Actual return on plan assets	72.6	87.5
Separation of former participants	(32.0)	-
Company contributions	63.8	65.0
Benefits paid	(84.1)	(79.1)
Transfers	(1.9)	(0.1)
Plan assets at fair value - end of year	<u>\$ 824.9</u>	<u>\$ 806.5</u>
<u>Reconciliation of accrued pension cost and total amount recognized</u>		
Funded status of the plan	\$ (517.3)	\$ (531.6)
Unrecognized net loss	435.6	443.6
Unrecognized prior service cost	10.0	9.1
Unrecognized net transition obligation	7.3	15.9
Accrued postretirement benefit before final contribution	(64.4)	(63.0)
Contribution made after measurement date but before March 31	3.7	-
Accrued pension cost	<u>\$ (60.7)</u>	<u>\$ (63.0)</u>
Accrued benefit liability	\$ (342.3)	\$ (383.2)
Intangible asset	17.3	25.0
Accumulated other comprehensive income, pre-tax	6.6	14.5
Regulatory assets	257.7	280.7
Accrued pension cost	<u>\$ (60.7)</u>	<u>\$ (63.0)</u>

The aggregated accumulated benefit obligation was \$1,170.9 million and the fair value of assets was \$828.6 million, measured as of December 31, 2005, and including contributions prior to March 31, 2006.

The Retirement Plan and the SERP currently have assets with a fair value that is less than the accumulated benefit obligation under the Retirement Plan and the SERP, primarily due to prior declines in the equity markets and historically low interest rate levels. As a result, PacifiCorp recognized minimum pension liabilities in the fourth quarters of the years ended March 31, 2006 and 2005. The minimum pension liability adjustment impacted

Regulatory assets, Intangible assets and Accumulated other comprehensive income. These adjustments are reflected in the table above and did not materially affect the consolidated results of operations. PacifiCorp requested and received accounting orders from the regulatory commissions in Utah, Oregon, Wyoming and Washington to classify most of the minimum pension liability adjustment as a Regulatory asset instead of a charge to Other comprehensive income. This increase to Regulatory assets will be adjusted in future periods as the difference between the fair value of the trust assets and the accumulated benefit obligation changes. PacifiCorp has determined that costs related to SFAS No. 87, *Employers' Accounting for Pensions* ("SFAS No. 87") for the Retirement Plan are currently recoverable in rates.

Retirement Plan assets are managed and invested in accordance with all applicable requirements, including the Employee Retirement Income Security Act and the Internal Revenue Code. PacifiCorp employs an investment approach that uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets at a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments as shown in the table below. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

Details of the Retirement Plan assets by investment category based on market values are as follows:

	Target	March 31,	
		2006	2005
Equity securities	55.0 %	58.5 %	56.1 %
Debt securities	35.0	34.5	33.9
Private equity	10.0	7.0	10.0

Although the SERP had no qualified assets as of March 31, 2006, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. Because this plan is nonqualified, the assets in the Rabbi trust are not considered plan assets. The cash surrender value of all of the policies included in the Rabbi trust plus the fair market value of other Rabbi trust investments was \$36.4 million at March 31, 2006 and \$34.7 million at March 31, 2005, net of amounts borrowed against the cash surrender value.

#### **Other Postretirement Benefits**

The cost of other postretirement benefits, including health care and life insurance benefits for eligible retirees, is accrued over the active service period of employees. The transition obligation represents the unrecognized prior service cost and is being amortized over a period of 20 years. PacifiCorp funds other postretirement benefits through a combination of funding vehicles. PacifiCorp contributed \$29.7 million for the year ended March 31, 2006; \$24.9 million for the year ended March 31, 2005; and \$25.3 million for the year ended March 31, 2004. The measurement date for plan assets and obligations is December 31 of each year.

For the postretirement benefit plan assets, PacifiCorp employs an investment approach that uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification, but also monitors and manages other aspects of risk through quarterly investment portfolio reviews,

annual liability measurements and periodic asset/liability studies.

The assets for other postretirement benefits are composed of three different trust accounts. The 401(h) account is invested in the same manner as the pension account. Each of the two Voluntary Employees' Beneficiaries Association Trusts has its own investment allocation strategies. Details of the Voluntary Employees' Beneficiaries Association Trusts' assets by investment category based on market values are as follows:

	Target	March 31,	
		2006	2005
Equity securities	65.0 %	66.0 %	66.4 %
Debt securities	35.0	34.0	33.6

Components of the net periodic postretirement benefit cost are summarized as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Service cost	\$ 8.8	\$ 8.5	\$ 7.4
Interest cost	30.4	31.0	34.3
Expected return on plan assets (a)	(26.3)	(26.4)	(26.6)
Amortization of unrecognized net transition obligation	12.2	12.2	12.2
Amortization of unrecognized loss	2.7	0.6	0.6
Amortization of prior service cost	2.1	0.1	-
Net periodic postretirement benefit cost	<u>\$ 29.9</u>	<u>\$ 26.0</u>	<u>\$ 27.9</u>

- (a) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets and is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur.

The change in the accumulated postretirement benefit obligation, change in plan assets and funded status of the postretirement plan is as follows:

(Millions of dollars)	March 31,	
	2006	2005
<u>Change in accumulated postretirement benefit obligation</u>		
Accumulated postretirement benefit obligation - beginning of year	\$ 528.3	\$ 555.3
Service cost	8.8	8.5
Interest cost	30.4	31.0
Plan participant contributions	8.3	7.2
Plan amendments	22.8	0.8
Separation of former participants	(8.9)	-
Actuarial loss (gain)	34.3	(34.4)
Benefits paid	(41.6)	(40.1)
Accumulated postretirement benefit obligation - end of year	<u>\$ 582.4</u>	<u>\$ 528.3</u>
<u>Change in plan assets</u>		
Plan assets at fair value - beginning of year	\$ 286.6	\$ 261.6
Actual return on plan assets	20.4	28.6
Company contributions	22.5	29.3
Plan participant contributions	8.3	7.2
Separation of former participants	(4.1)	-
Net benefits paid	(41.6)	(40.1)
Plan assets at fair value - end of year	<u>\$ 292.1</u>	<u>\$ 286.6</u>
<u>Reconciliation of accrued postretirement costs and total amount recognized</u>		
Funded status of the plan	\$ (290.3)	\$ (241.7)
Unrecognized net transition obligation	81.1	94.6
Unrecognized prior service cost	22.1	1.4
Unrecognized loss	138.1	100.1
Accrued postretirement benefit cost, before final contribution	(49.0)	(45.6)
Contribution made after measurement date but before March 31	29.7	24.9
Accrued postretirement cost	<u>\$ (19.3)</u>	<u>\$ (20.7)</u>

The assumed health care cost trend rates are as follows:

	March 31,		
	2006	2005	2004
Initial health care cost trend - under 65	10.0 %	7.5 %	8.5 %
Initial health care cost trend - over 65	10.0	9.5	10.5
Ultimate health care cost trend rate	5.0	5.0	5.0
Year that rate reaches ultimate - under 65	2011	2007	2007
Year that rate reaches ultimate - over 65	2011	2009	2009

The health care cost trend rate assumption has a significant effect on the amounts reported. An annual increase or decrease in the assumed medical care cost trend rate of 1.0% would affect the accumulated postretirement benefit obligation and the service and interest cost components as follows:

(Millions of dollars)	One Percent	
	Increase	Decrease
Accumulated postretirement benefit obligation	\$ 43.7	\$ (35.5)
Service and interest cost components	2.8	(2.4)

### **Future Contributions and Benefit Payments**

In April 2006, PacifiCorp contributed \$72.7 million to its Retirement Plan. In addition, PacifiCorp expects to contribute another \$11.0 million to its pension plans, as well as \$36.6 million to its postretirement benefit plan, during the 12 months ending March 31, 2007. The benefit payments expected to be paid, which reflect expected future service and the Medicare Part D subsidy expected to be received, are as follows:

(Millions of dollars)	Retirement Plans	Other Postretirement Benefits	Medicare Part D Subsidy Receipts
12 months ending March 31,			
2007	\$ 92.5	\$ 35.8	\$ (3.0)
2008	92.4	37.9	(3.4)
2009	93.6	40.0	(3.9)
2010	94.7	42.1	(4.3)
2011	97.7	44.4	(4.6)
2012 to 2016 (inclusive)	541.2	248.2	(29.9)

### **Employee Savings Plan**

PacifiCorp has an employee savings plan (the "Savings Plan") that qualifies as a tax-deferred arrangement under the Internal Revenue Code. Eligible employees of adopting affiliates are those who are not temporary, casual, leased or covered by a collective bargaining agreement that does not provide for participation. Employees of any company within the PacifiCorp controlled group of companies that has not adopted the Savings Plan are not eligible. Participating United States employees may defer up to 50.0% of their compensation, subject to certain statutory limitations. Compensation includes base pay, overtime and annual incentive, but is limited to the maximum allowable under the Internal Revenue Code. Employees can select a variety of investment options. PacifiCorp matches 50.0% of employee contributions on amounts deferred up to 6.0% of total compensation, with that portion vesting over the initial five years of an employee's qualifying service. Thereafter, PacifiCorp's contributions vest immediately. PacifiCorp's matching contribution is allocated based on the employee's investment selections. PacifiCorp may also make an additional contribution equal to a percentage of the employee's eligible earnings. This additional contribution is allocated based on the employee's investment selections or to the money market fund if the employee has made no selections. These contributions are immediately vested. PacifiCorp's contributions to the Savings Plan were \$22.5 million for the year ended March 31, 2006; \$20.2 million for the year ended March 31, 2005; and \$19.3 million for the year ended March 31, 2004; and represent amounts expensed for such periods.

### **Severance**

As a result of general workforce reductions and ScottishPower's corporate restructuring during the year ended March 31, 2006, PacifiCorp incurred severance expense of \$4.1 million under its severance and other benefit plans related to the involuntary termination of approximately 62 employees. Services provided by these employees are expected to be complete by March 31, 2007.

As a result of the MEHC acquisition, PacifiCorp has experienced organizational changes and additional workforce reductions resulting in severance expense of \$12.9 million during the year ended March 31, 2006 under its severance and other benefit plans, primarily related to the involuntary termination of 29 employees. Additional severance expense is expected to be incurred in the future as additional organizational changes occur.

#### Note 18 – Stock-Based Compensation

**PacifiCorp Stock Incentive Plan (“PSIP”)** - During 1997, PacifiCorp adopted the PSIP. The exercise price of options granted under the PSIP was equal to the market value of the common stock on the date of the grant. ScottishPower took control of the plan upon completion of its merger and all stock options were converted into options to purchase ScottishPower American Depository Shares. The PSIP expired on November 29, 2001 and all outstanding options under the plan were fully vested as of March 31, 2005.

As a result of the sale of PacifiCorp to MEHC and in accordance with the PSIP provisions regarding a change in control, all outstanding options must be exercised no later than 12 months after the date of the sale of PacifiCorp; otherwise they will be forfeited.

**ScottishPower Executive Share Option Plan (“ExSOP”)** - In prior years, a select group of PacifiCorp employees received grants of stock options under the ScottishPower ExSOP. Certain grants awarded in May 2001 were performance-based awards which resulted in \$2.0 million of compensation expense included in Operations and maintenance expense for the year ended March 31, 2005.

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, all ExSOP options held by PacifiCorp employees became fully vested in accordance with the change-in-control provisions of the ExSOP. The change-in-control provisions also provide that all outstanding options are exercisable up to the later of 12 months after the date of the sale of PacifiCorp or 42 months after the date of original option grant. Options that are not exercised within this time period will be forfeited. As of the date of the sale, PacifiCorp ceased to participate in the plan but as of March 31, 2006, there are still options outstanding and exercisable by PacifiCorp employees.

The table below summarizes the stock option activity under the PSIP and the ExSOP.

	PSIP		ExSOP	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
<u>ScottishPower American Depository Shares</u>				
Outstanding options at March 31, 2003	3,403,251	\$ 31.67	935,054	\$ 23.55
Granted	-	-	780,901	24.40
Exercised	(147,496)	25.55	(25,508)	23.55
Forfeited	(331,706)	34.65	(41,991)	23.93
Outstanding options at March 31, 2004	2,924,049	31.64	1,648,456	23.94
Granted	-	-	763,843	28.72
Exercised	(750,126)	26.10	(483,667)	23.84
Forfeited	(40,310)	35.36	(30,136)	26.37
Outstanding options at March 31, 2005	2,133,613	33.52	1,898,496	25.85
Exercised	(1,325,284)	31.32	(1,404,637)	25.58
Forfeited	(30,578)	35.86	(16,096)	27.59
Transfers due to separation	(68,710)	37.35	(164,677)	25.56
Outstanding options at March 31, 2006	709,041	37.15	313,086	27.15

Information with respect to options outstanding and options exercisable under the PSIP and the ExSOP as of March 31, 2006 and 2005 were as follows:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)	Number of Shares	Weighted Average Exercise Price
Year ended March 31, 2006					
PSIP					
\$25.70 - \$36.64	268,205	\$ 31.25	1.0	268,205	\$ 31.25
\$39.99 - \$41.38	440,836	40.74	1.0	440,836	40.74
Total	709,041	37.15	1.0	709,041	37.15
ExSOP					
\$23.55 - \$28.72	313,086	\$ 27.15	1.4	313,086	\$ 27.15
Year ended March 31, 2005					
PSIP					
\$25.70 - \$36.64	1,589,323	\$ 31.05	4.2	1,589,323	\$ 31.05
\$39.99 - \$43.83	544,290	40.72	3.0	544,290	40.72
Total	2,133,613	33.52	3.9	2,133,613	33.52
ExSOP					
\$23.55 - \$28.72	1,898,496	\$ 25.85	8.2	182,134	\$ 23.97

**ScottishPower Long-Term Incentive Plan** - In prior years, a select group of PacifiCorp employees received grants of performance share awards under ScottishPower's Long-Term Incentive Plan. The number of shares that actually vest is dependent upon the outcome of certain performance measures over a three-year period. The plan's change-in-control provisions resulted in removal of the employees' future service requirement as of the date of the acquisition but retained the three-year performance requirements. As a result, the number of shares that ultimately vest at the end of the performance period, if any, will be prorated to reflect only the portion of the three-year period which had elapsed between the date of original grant and the date of the sale of PacifiCorp to MEHC. During the year ended March 31, 2006, no stock-based compensation expense was recorded because the performance measures were not yet reached.

**Deferred Share Program** - In May 2004, ScottishPower implemented a deferred share program under which certain PacifiCorp employees were granted an annual stock bonus award based on a fixed dollar amount but distributable in ScottishPower American Depository Shares with the number of shares to be determined by the quoted market price of the shares at the date of issuance. Historically, compensation expense was accrued throughout the year in which the employee services were rendered and awards earned. During the year ended March 31, 2005, \$3.1 million of compensation costs were accrued. However, as a result of the sale of PacifiCorp to MEHC, the program was modified during the year ended March 31, 2006 to provide for a cash payment rather than a share-based payment. The plan was discontinued as of April 1, 2006.

## Note 19 - Income Taxes

The difference between the United States federal statutory tax rate and the effective income tax rate attributed to income from continuing operations is as follows:

	Years Ended March 31,		
	2006	2005	2004
Federal statutory rate	35.0 %	35.0 %	35.0 %
State taxes, net of federal benefit	2.9	3.8	3.6
Effect of regulatory treatment of depreciation differences	2.5	4.1	4.5
Tax reserves	1.1	(0.9)	(3.1)
Tax credits	(2.6)	(2.3)	(2.5)
Other	(3.3)	0.4	(0.8)
Effective income tax rate	<u>35.6 %</u>	<u>40.1 %</u>	<u>36.7 %</u>

The provision for income taxes is summarized as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Current			
Federal	\$ 167.3	\$ 58.6	\$ 63.0
State	18.2	(10.1)	1.0
Total	<u>185.5</u>	<u>48.5</u>	<u>64.0</u>
Deferred			
Federal	19.7	112.6	77.8
State	2.1	15.3	10.6
Total	<u>21.8</u>	<u>127.9</u>	<u>88.4</u>
Investment tax credits	<u>(7.9)</u>	<u>(7.9)</u>	<u>(7.9)</u>
Total income tax expense	<u>\$ 199.4</u>	<u>\$ 168.5</u>	<u>\$ 144.5</u>

The tax effect of temporary differences giving rise to significant portions of PacifiCorp's deferred tax liabilities and deferred tax assets were as follows:

(Millions of dollars)	March 31,	
	2006	2005
Deferred tax liabilities:		
Property, plant and equipment	\$ 1,531.2	\$ 1,512.3
Regulatory assets	623.0	667.9
Derivative contract regulatory assets	35.9	64.5
Other deferred tax liabilities	114.3	126.3
	<u>2,304.4</u>	<u>2,371.0</u>
Deferred tax assets:		
Regulatory liabilities	(316.9)	(325.2)
Employee benefits	(170.9)	(185.4)
Derivative contracts	(44.0)	(102.6)
Other deferred tax assets	(134.5)	(126.8)
	<u>(666.3)</u>	<u>(740.0)</u>
Net deferred tax liability	<u>\$ 1,638.1</u>	<u>\$ 1,631.0</u>

PacifiCorp made net income tax payments of \$140.0 million for the year ended March 31, 2006; \$92.0 million for the year ended March 31, 2005; and \$114.1 million for the year ended March 31, 2004. The income tax payments include payments for current federal and state income taxes, as well as amounts paid in settlement of prior years' liabilities as a result of income tax proceedings.

PacifiCorp has established, and periodically reviews, an estimated contingent tax reserve on its Consolidated Balance Sheets to provide for the possibility of adverse outcomes in tax proceedings. The net federal and state contingency reserve increased \$6.1 million during the year ended March 31, 2006 primarily due to new issues identified for tax years ended after March 31, 2000. The Internal Revenue Service started its examination of the 2001, 2002 and 2003 tax years in October 2004. PacifiCorp anticipates that final settlement and payment on settled issues and other unresolved issues will not have a material adverse impact on its consolidated financial position or results of operations.

The sale of PacifiCorp to MEHC on March 21, 2006 triggered the recognition of a deferred intercompany gain or loss for tax purposes. The recognition of the tax effects of this item is considered to have been recognized immediately prior to the closing of the sale of PacifiCorp while it was part of the PHI consolidated group. PacifiCorp is currently unable to estimate the amount of the tax effect, if any, or determine a range of the potential tax effect. Due to the uncertainty of the amount of the deferred intercompany gain or loss, no adjustments have been recorded as of March 31, 2006.

Pursuant to a formal agreement with PHI and ScottishPower, any tax liabilities generated as a result of a deferred intercompany gain would be recorded as an equity contribution to PacifiCorp. Additionally, as this transaction is deemed to be with shareholders, the net tax expense would be recorded as a reduction in Common shareholder's capital similar to a return of capital distribution. As a result, there would be no net impact to PacifiCorp's Common shareholder's capital, statement of financial position or results of operations.

If a deferred intercompany loss is determined to exist, PacifiCorp would be required to recognize the tax benefit of the deferred intercompany loss as an increase in Common shareholder's capital and establish a corresponding tax receivable or deferred tax asset, depending on whether PacifiCorp would be able to currently utilize the capital loss. In the event a deferred tax asset is created with respect to the capital loss, it will be necessary to determine whether a valuation allowance should be established against the deferred tax asset.

At March 31, 2006, PacifiCorp had no federal or state net operating loss carryforwards. At March 31, 2005, PacifiCorp had total available federal net operating loss carryforwards of approximately \$2.7 million and no state net operating loss carryforwards. PacifiCorp has Oregon business energy tax credits of approximately \$0.6 million at March 31, 2006 available to reduce future income tax liabilities. These credits begin to expire in 2012. PacifiCorp has Idaho investment tax credits of approximately \$1.9 million at March 31, 2006 that are available to reduce future income tax liabilities. These credits begin to expire in 2017. PacifiCorp anticipates utilizing the tax credits prior to the expiration dates.

#### Note 20 - Concentration of Customers

During the year ended March 31, 2006, no single retail customer accounted for more than 2.0% of PacifiCorp's retail electric revenues, and the 20 largest retail customers accounted for 13.0% of total retail electric revenues. The geographical distribution of PacifiCorp's retail operating revenues for the year ended March 31, 2006 was: Utah, 40.9%; Oregon, 29.3%; Wyoming, 13.3%; Washington, 8.4%; Idaho, 5.7%; and California, 2.4%.

#### Note 21 - Subsequent Events

On May 10, 2006, the PacifiCorp Board of Directors determined to change PacifiCorp's fiscal year-end from March 31 to December 31. PacifiCorp's report covering the transition period beginning April 1, 2006 and ending December 31, 2006 will be filed on Form 10-K.

### SUPPLEMENTAL INFORMATION

#### QUARTERLY FINANCIAL DATA (UNAUDITED)

(Millions of dollars, except per share amounts)	Quarters Ended			
	June 30	September 30	December 31	March 31
<b>2006</b>				
Revenues	\$ 881.4	\$ 620.7	\$ 1,165.0	\$ 1,229.6
Income from operations	135.9	129.2	256.2	270.7
Net income	46.4	39.4	127.8	147.1
Earnings on common stock	45.9	38.9	127.2	146.6
Common dividends declared per share	16.3¢	16.3¢	16.3¢	4.8¢
Common dividends paid per share	16.3¢	16.3¢	16.3¢	4.8¢
<b>2005</b>				
Revenues	\$ 747.8	\$ 828.7	\$ 849.5	\$ 622.8
Income from operations	129.9	165.3	155.2	206.0
Net income	50.9	61.9	51.3	87.6
Earnings on common stock	50.4	61.4	50.7	87.1
Common dividends declared per share	15.5¢	15.5¢	15.5¢	15.5¢
Common dividends paid per share	15.5¢	15.5¢	15.5¢	15.5¢

On March 31, 2006, MEHC was the only common shareholder of record.

## **ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE**

No information is required to be reported pursuant to this item.

### **ITEM 9A. CONTROLS AND PROCEDURES**

PacifiCorp maintains disclosure controls and procedures designed to provide reasonable assurance that material information required to be disclosed by it in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that the information is accumulated and communicated to PacifiCorp's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. PacifiCorp performed an evaluation, under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of PacifiCorp's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, PacifiCorp's management, including its Chief Executive Officer and Chief Financial Officer, concluded that the disclosure controls and procedures were effective as of the end of the period covered by this report.

On March 21, 2006, MEHC completed its purchase of PacifiCorp, at which time PacifiCorp became a subsidiary of MEHC. Although PacifiCorp has maintained its disclosure controls and procedures that were in effect prior to the acquisition, subsequent to the acquisition there have been material changes in PacifiCorp's internal control over financial reporting. The material changes are due to the effect of the acquisition on PacifiCorp's control environment, which includes changes in the composition of the board of directors, PacifiCorp's organizational structure, audit committee oversight and its corporate governance framework. PacifiCorp believes these changes have not negatively affected its internal control over financial reporting.

During the three months ended March 31, 2006, there was no other change in PacifiCorp's internal control over financial reporting identified in connection with the evaluation required by paragraph (d) of Securities Exchange Act of 1934 Rules 13a-15 or 15d-15 that occurred that has materially affected, or is reasonably likely to materially affect, PacifiCorp's internal control over financial reporting.

### **ITEM 9B. OTHER INFORMATION**

No information is required to be reported pursuant to this item.

### **PART III**

#### **ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT**

The following is a list of directors and executive officers of PacifiCorp. There are no family relationships among the executive officers of PacifiCorp. Officers of PacifiCorp are normally elected annually.

**Name and Age**

**Business Experience Past Five Years**

**Gregory E. Abel (43)**

Chief Executive Officer and Chairman. Director since March 2006.

Mr. Abel was elected Chief Executive Officer and Chairman of PacifiCorp's Board of Directors in March 2006. Mr. Abel is also the President and Chief Operating Officer and a director of MEHC. Mr. Abel joined MEHC in 1992.

**Douglas L. Anderson (48)**

Director since March 2006.

Mr. Anderson is the Senior Vice President, General Counsel and Corporate Secretary of MEHC. Mr. Anderson joined MEHC in February 1993 and has served in various legal positions, including General Counsel of MEHC's independent power affiliates. Prior to that, Mr. Anderson was a corporate attorney in private practice.

**William J. Fehrman (45)**

President, PacifiCorp Energy. Director since March 2006.

Mr. Fehrman was elected President, PacifiCorp Energy in March 2006 and has responsibility for PacifiCorp's electric generation, commercial and energy trading and coal-mining operations. He joined MEHC in March 2006 to oversee integration activities of MEHC's acquisition of PacifiCorp. Prior to joining MEHC, Mr. Fehrman was President and Chief Executive Officer of Nebraska Public Power District in Columbus, Nebraska. He joined Nebraska Public Power in 1981, serving as its President and Chief Executive Officer since January 2003 and before that as Vice President of Energy Supply.

**Brent E. Gale (54)**

Director since March 2006.

Mr. Gale was appointed Senior Vice President of Regulation and Legislation of MEHC in March 2006. Previously he had been Senior Vice President of MidAmerican Energy Company, a MEHC subsidiary, since July 2004. Mr. Gale has served in various legal, regulatory and strategic positions with MidAmerican Energy Company and its predecessors for more than five years prior to that.

**Patrick J. Goodman (39)**

Director since March 2006.

Mr. Goodman is Senior Vice President and Chief Financial Officer of MEHC. Mr. Goodman joined MEHC in 1995 and has served in various financial positions, including Chief Accounting Officer.

**Andrew P. Haller (54)**

Senior Vice President, General Counsel and Corporate Secretary. Director since May 2003.

Mr. Haller joined PacifiCorp as its Senior Vice President, General Counsel and Corporate Secretary in December 2000 and was also named General Counsel for Pacific Power in March 2006. Prior to joining PacifiCorp, he was chief executive for the United States operations of Kvaerner Process, a position he assumed in 1999. Mr. Haller began his career with Kvaerner in 1987, and held various senior counsel and management positions, including Senior Vice President and General Counsel-Americas. From 1998 to 1999, he served as the Associate General Counsel for the parent company, Kvaerner ASA, in its United States corporate headquarters.

**Nolan E. Karras (61)**

Director since February 1993.

Mr. Karras is President of The Karras Company, Inc., an investment adviser, and has served in that capacity since 1983. He is Chief Executive Officer of Western Hay Company, Inc., a non-executive director of Scottish Power plc and Beneficial Life Insurance Company and is a Registered Principal for Raymond James Financial Services.

**A. Robert Lasich (46)**

Vice President and General Counsel, PacifiCorp Energy. Director since March 2006.

Mr. Lasich joined PacifiCorp and was elected to his current positions in March 2006. Previously he served as Vice President of MEHC with responsibility for integration and transition matters related to the acquisition of PacifiCorp since July 2005. Prior to that, Mr. Lasich was Vice President of Gas Supply and Trading for MidAmerican Energy Company since August 2004. He joined MidAmerican Energy Company in October 1997 and has also served as a senior attorney in its legal department.

**Mark C. Moench (50)**

Senior Vice President and General Counsel, Rocky Mountain Power. Director since March 2006.

Mr. Moench joined PacifiCorp and was elected to his current positions in March 2006. Previously he served as Senior Vice President, Law, of MEHC with responsibility for regulatory approvals of the PacifiCorp acquisition since June 2005. Prior to that, Mr. Moench was Vice President and General Counsel of Kern River Gas Transmission Company since 2002, when Kern River was acquired by MEHC from the Williams Companies, Inc., which he joined in 1987. Mr. Moench served the Williams Companies in various senior legal positions, including as General Counsel of Kern River.

**Richard D. Peach (42)**

Senior Vice President and Chief Financial Officer. Director since May 2003.

Mr. Peach was elected PacifiCorp's Chief Financial Officer effective January 2003 and elected Senior Vice President in March 2006. Mr. Peach had served previously as Senior Vice President of Finance since March 2002. Prior to his appointment as Chief Financial Officer, he also served as Group Controller for Scottish Power plc from March 2000 to December 2002, Head of Customer Services, Energy Supply for ScottishPower from April 1999 to March 2000 and in various other management positions with ScottishPower since 1995.

**A. Richard Walje (54)**

President, Rocky Mountain Power. Director since July 2001.

Mr. Walje was elected President, Rocky Mountain Power in March 2006 and has responsibility for the electric distribution operations of PacifiCorp in Utah, Idaho and Wyoming. Mr. Walje previously served as PacifiCorp's Executive Vice President since April 2004 and as Chief Information Officer since May 2000. Previously he served as PacifiCorp's Senior Vice President of Corporate Business Services from May 2001 to April 2004 and as PacifiCorp's Vice President for Transmission and Distribution Operations and Customer Service from 1998 to 2000. Mr. Walje has been with PacifiCorp since 1986.

**Stanley K. Watters (47)**

President, Pacific Power. Director since March 2006.

Mr. Watters was elected President, Pacific Power in March 2006 and has responsibility for the electric distribution operations of PacifiCorp in Oregon, Washington and California. Mr. Watters was elected Senior Vice President of Commercial and Trading in June 2003. Mr. Watters served as Vice President of Trading and Origination from July 2001 to June 2003 and as Managing Director of Wholesale Energy Services since 1998. Mr. Watters has been with PacifiCorp since 1982.

**Bruce N. Williams (47)**

Treasurer.

Mr. Williams has served as PacifiCorp's Treasurer since February 2000. Prior to being elected Treasurer, he served as Assistant Treasurer of PacifiCorp and has been with PacifiCorp since 1985.

In addition to following MEHC's Code of Business Conduct and Berkshire Hathaway's Code of Business Conduct and Ethics Policy, which provide a basis for employee ethical standards and conduct for all employees, the PacifiCorp Board of Directors previously approved and implemented a "Code of Ethics for Principal Officers" designed to promote the integrity of PacifiCorp's financial reporting and legal compliance. The Code of Ethics for Principal Officers applies to PacifiCorp's Chief Executive Officer and its financial and accounting officers. The Guide to Business Conduct and Code of Ethics for Principal Officers are available in the "About Us - Company Overview" section of PacifiCorp's website at [www.pacifiCorp.com](http://www.pacifiCorp.com). PacifiCorp intends to make available on its website any amendment to, or waiver from, the Code of Ethics for Principal Officers as the Code applies to PacifiCorp's Chief Executive Officer and its financial and accounting officers.

Through its affiliation with Berkshire Hathaway, PacifiCorp participates in The Network, an independent company that employees and vendors can call to report business conduct issues confidentially and anonymously involving fraud, financial reporting irregularities, misrepresentation of financial reports, non-compliance with internal controls, or suspected illegal or unethical activity.

Because PacifiCorp's common stock is indirectly, wholly owned by MEHC, its Board of Directors consists primarily of internal executives and it is not required to have an audit committee. However, the audit committee of MEHC acts as the audit committee for PacifiCorp.

## **ITEM 11. EXECUTIVE COMPENSATION**

### **PACIFICORP BOARD OF DIRECTORS REPORT ON EXECUTIVE COMPENSATION**

#### **Introduction**

The PacifiCorp Board of Directors submits this report on executive compensation, which outlines the compensation provided to PacifiCorp's executive officers. For most of the year ended March 31, 2006, PacifiCorp was owned by ScottishPower, and this report generally reflects the executive compensation philosophy, practices and programs maintained under ScottishPower ownership. PacifiCorp's acquisition by MEHC on March 21, 2006 generally did not result in material changes to PacifiCorp executive compensation practices, but any such changes are described in this Item 11.

#### **Compensation Committee Interlocks and Insider Participation**

Under ScottishPower ownership, the Remuneration Committee of the ScottishPower Board of Directors, assisted by its outside advisors, had the responsibility to approve compensation levels and executive compensation plans for the PacifiCorp Chief Executive Officer, as well as any ScottishPower executive officers serving as PacifiCorp executive officers in a dual capacity, and to review compensation for other executive officers and senior management of PacifiCorp. During the year ended March 31, 2006, the Remuneration Committee was composed entirely of independent, non-executive directors. With the exception of any compensation requiring review by the Remuneration Committee, the Compensation Committee of the PacifiCorp Board of Directors, which under ScottishPower ownership consisted of the PacifiCorp Chief Executive Officer and, at various times during the year ended March 31, 2006, the ScottishPower Chief Executive Officer, the ScottishPower Human Resources Director and PacifiCorp's General Counsel, had responsibility for approving compensation levels and executive compensation plans for executive officers of PacifiCorp. The Remuneration Committee also approved any stock-based compensation to PacifiCorp executive officers, all of which was in the form of ScottishPower equity.

Effective upon MEHC's acquisition of PacifiCorp, PacifiCorp's Board of Directors eliminated its Compensation Committee and delegated its duties to the Chairman of the Board of Directors, Gregory E. Abel. Mr. Abel also serves as PacifiCorp's Chief Executive Officer and as MEHC's President and Chief Operating Officer. He is employed by MEHC and receives no compensation from PacifiCorp or specific compensation from MEHC for his PacifiCorp service; accordingly, references to executive officers in this Item 11 exclude Mr. Abel unless otherwise indicated. The following describes the components of PacifiCorp's executive compensation program and the basis upon which recommendations and determinations were made for the year ended March 31, 2006.

#### **Compensation Philosophy**

PacifiCorp's philosophy is that executive compensation should be linked closely to corporate and operational performance, customer service and increases in shareholder value. PacifiCorp's executive compensation program has the following objectives:

- (i) provide competitive total compensation that enables PacifiCorp to attract and retain key executives;
- (ii) provide variable compensation opportunities that are linked to PacifiCorp, operational area, and individual performance; and
- (iii) establish an appropriate balance between incentives focused on short-term objectives and those encouraging sustained performance improvements.

Qualifying compensation for deductibility under Internal Revenue Code Section 162(m) is one of the factors that PacifiCorp considers in designing PacifiCorp's incentive compensation arrangements for executive officers. Internal Revenue Code Section 162(m) limits to \$1.0 million the annual deduction by a publicly held corporation of compensation paid to any executive officer, except with respect to certain forms of incentive compensation that qualify for exclusion. Although it is the intent to design and administer compensation programs that maximize deductibility, PacifiCorp views the objectives outlined above as more important than compliance with the technical requirements necessary to exclude compensation from the deductibility limit of Internal Revenue Code Section

162(m). Nevertheless, with the exception of severance payments made to PacifiCorp's former President and Chief Executive Officer, Judith A. Johansen, PacifiCorp believes that nearly all compensation paid to the executive officers for services rendered in the year ended March 31, 2006, is fully deductible.

### **Compensation Program Components**

During the year ended March 31, 2006, the compensation programs were focused on market-based comparisons on the relevant industry for each executive officer. The electric utility industry was utilized as the exclusive basis for market comparison for positions with a principal focus on electric operations. For positions with a corporate-wide focus, the general industry and electric utility industry were used for market comparison. In all cases, compensation is targeted at market median levels, with an assumption that total compensation greater than market median, in any specific time period, anticipates that PacifiCorp and industry performance exceeds the median performance of peer companies.

PacifiCorp's executive compensation programs have three principal elements: base salaries, annual incentive compensation and long-term incentive compensation, as described below.

#### **Base Salaries**

Base salaries and target incentive amounts are reviewed for adjustment at least annually based upon competitive pay levels, individual performance and potential, and changes in duties and responsibilities. Base salary and the target incentive are set at a level such that total annual compensation for satisfactory performance would approximate the median of pay levels in the comparison group used to develop competitive data. In the year ended March 31, 2006, the base salary of each executive officer was increased, based on market analysis, to reflect competitive market changes, individual performance and changes in the responsibilities of some officers.

#### **Annual Incentive Compensation**

All PacifiCorp executive officers, including those listed in the Summary Compensation Table other than Mr. Abel, participate in PacifiCorp's Annual Incentive Plan (the "AIP"). In May 2006, PacifiCorp determined that named executive officers are eligible under certain conditions for payments under the AIP in June 2006 as follows: Judith A. Johansen, \$393,751; Andrew P. Haller, \$185,980; A. Richard Walje, \$158,789; Richard D. Peach, \$184,356; Stanley K. Watters, \$131,016; and Matthew Wright, \$142,916.

#### **Long-Term Incentive Compensation**

In May 2005, the ScottishPower Remuneration Committee approved grants of performance share awards under ScottishPower's Long-Term Incentive Plan (the "LTIP") for a select group of PacifiCorp executive officers and other senior managers. LTIP awards were also made in April 2004 to certain executive officers and senior managers. The LTIP provides for awards of performance shares that link the rewards closely between management and shareholders and focus on long-term corporate performance. The awards will vest only if the Remuneration Committee is satisfied that certain threshold customer service and financial performance measures are achieved. The number of shares that actually vest depends upon ScottishPower's comparative Total Shareholder Return performance over a three-year performance period. Vested shares are released to participants only after the conclusion of the performance period. In addition to the criteria described above, the vesting of LTIP awards held by PacifiCorp executive officers and senior managers will be prorated to reflect only the portion of the three-year performance period in which PacifiCorp was owned by ScottishPower.

In April 2004, the ScottishPower Remuneration Committee also approved grants of stock options under the ExSOP for certain executive officers and other senior managers, which were awarded in May 2004. These grants were the last stock options awarded under the ExSOP. Upon the closing of PacifiCorp's sale to MEHC, all outstanding ExSOP options vested in full. A number of restricted stock and stock option awards originally made under the PSIP, which was assumed by ScottishPower in connection with its acquisition of PacifiCorp in 1999 and expired in 2001, remain outstanding but are fully vested. Except for the ExSOP grants awarded in May 2004, ExSOP and PSIP awards relate to ScottishPower American Depositary Shares or Ordinary Shares and will remain outstanding until March 21, 2007. The ExSOP awards granted in May 2004, will remain outstanding until November 2007.

In May 2004, the ScottishPower Remuneration Committee approved a new program to replace the ExSOP, called the Deferred Share Program, which was part of the AIP for executive officers and senior management. Eligible employees received an increase to their AIP maximum target incentive payment, with the increase paid in ScottishPower American Depositary Shares, for the year ended March 31, 2005. For the year ended March 31, 2006, the Deferred Share Program was modified and potential payments for eligible employees under the program were added to cash payments under the AIP. This program was discontinued as of April 1, 2006.

William Fehrman, President of PacifiCorp Energy, currently participates in MEHC's Long-Term Incentive Partnership Plan. The participation of the other named executive officers (excluding Mr. Abel, who is not a participant) in the plan will be evaluated for PacifiCorp's fiscal year ending December 31, 2007. A copy of the plan is attached as Exhibit 10.71 to the MEHC Annual Report on Form 10-K for the year ended December 31, 2004.

### **Compensation of Directors**

Directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board meetings.

### **Executive Compensation**

The following table sets forth information concerning compensation for services in all capacities to PacifiCorp for the years ended March 31, 2006, 2005 and 2004 of the Chief Executive Officer of PacifiCorp, the next four other most highly compensated executive officers of PacifiCorp who were serving as executive officers at the end of the last completed fiscal year and two former PacifiCorp executive officers, either of whom would have been among the four other most highly compensated executive officers if they had been serving in such capacity as of March 31, 2006.

# Summary Compensation Table

Name and Principal Position	Year	Annual Compensation (b)		All Other Compensation (c)	Long-Term Compensation			
		Salary (c)	Bonus (d)		Restricted Stock Awards	Securities Underlying Options	LTIP Payout (f)	ScottishPower Performance Shares (g)
Gregory E. Abel (a) Chairman and Chief Executive Officer		-	-	-	-	-	-	-
Judith A. Johansen (h) Former President and Chief Executive Officer	2006	\$ 808,042	\$ 393,751	\$ 4,115,523	-	-	\$ -	15,839
	2005	743,750	437,500	23,311	-	52,228	-	19,916
	2004	589,394	337,500	22,883	-	61,475	-	12,458
Andrew P. Haller Senior Vice President, General Counsel and Corporate Secretary	2006	361,349	185,980	108,955	-	-	-	3,774
	2005	334,480	167,137	20,515	-	11,667	-	4,746
	2004	327,996	190,109	20,165	-	13,530	-	5,484
A. Richard Walje President, Rocky Mountain Power	2006	343,004	158,789	104,409	-	-	-	5,374
	2005	317,307	158,108	20,270	-	16,613	-	6,757
	2004	299,544	127,557	83,173	-	17,751	-	7,195
Richard D. Peach Senior Vice President and Chief Financial Officer	2006	380,456	209,088	248,494	-	-	-	5,704
	2005	210,654	153,987	100,368	-	11,406	-	6,844
	2004	200,291	136,150	115,899	-	10,977	-	6,586
Stanley K. Watters President, Pacific Power	2006	277,671	131,016	88,326	-	-	58,102	2,900
	2005	256,875	128,550	20,100	-	8,965	-	3,647
	2004	243,693	130,728	22,544	-	8,865	-	3,593
Matthew Wright (i) Former Executive Vice President	2006	316,545	142,916	2,028,821	-	-	-	4,959
	2005	292,481	141,945	151,425	-	15,331	-	6,236
	2004	253,612	127,527	62,766	-	10,502	-	6,301
Michael J. Pittman (j) Former Senior Vice President	2006	190,909	268,125	1,839,328	-	-	-	5,490
	2005	323,750	189,000	20,329	-	33,948	-	6,904
	2004	313,125	187,500	20,097	-	38,729	-	7,849

- (a) Mr. Abel receives no compensation from PacifiCorp or specific compensation from MEHC for his PacifiCorp service. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 001-14881) for executive compensation information for Mr. Abel.
- (b) May include amounts deferred pursuant to the Compensation Reduction Plan, under which key executives and directors may defer receipt of cash compensation until retirement or a preset future date. Amounts deferred are invested in ScottishPower American Depositary Shares or a cash account on which interest is paid at a rate equal to the Moody's Intermediate Corporate Bond Yield for AA-rated Public Utility Bonds.
- (c) Salary includes foreign housing benefits paid to Mr. Peach and Mr. Wright. The amounts for Mr. Peach were \$8,638 for the year ended March 31, 2006, \$64,944 for the year ended March 31, 2005 and \$68,513 for the year ended March 31, 2004. The amount for Mr. Wright was \$39,380 for the year ended March 31, 2004.
- (d) Bonus includes the value of ScottishPower American Depositary Shares awarded under the AIP Deferred Share Program for the fiscal year ended March 31, 2005.
- (e) Amounts shown for the year ended March 31, 2006, include:
- (i) Company contributions to the PacifiCorp Employee Savings and Stock Ownership Plan (the "Savings

- Plan”) of \$12,850 for Ms. Johansen, \$11,366 for Mr. Haller, \$11,259 for Mr. Walje, \$7,531 for Mr. Peach, \$11,165 for Mr. Watters, \$11,258 for Mr. Wright, and \$7,240 for Mr. Pittman.
- (ii) Portions of premiums on term life insurance policies that PacifiCorp paid in the amounts of \$2,344 for Ms. Johansen, \$1,088 for Mr. Haller, \$1,072 for Mr. Walje, \$1,179 for Mr. Peach, \$836 for Mr. Watters, \$953 for Mr. Wright, and \$513 for Mr. Pittman. These benefits are available to all employees.
  - (iii) Annual vehicle allowances of \$9,263 paid to Ms. Johansen, \$9,375 paid to each of Messrs. Haller, Walje, Watters, and Wright, \$4,800 paid to Mr. Peach and \$4,875 paid to Mr. Pittman.
  - (iv) Retention payments in the amounts of \$87,126 to Mr. Haller, \$82,703 to Mr. Walje, \$62,500 to Mr. Peach, \$66,950 to Mr. Watters and \$76,323 to Mr. Wright.
  - (v) Additional international assignment payments of \$42,195 to Mr. Peach and \$37,868 to Mr. Wright for the year ended March 31, 2006. Also includes international assignee localization payments of \$130,289 to Mr. Peach and \$12,611 to Mr. Wright for the year ended March 31, 2006.
  - (vi) Severance benefits, including enhancements related to PacifiCorp’s change in control, paid during the year ended, or payable or accrued as of, March 31, 2006, in the amounts of \$4,091,066 to Ms. Johansen, \$1,880,433 to Mr. Wright and \$1,826,700 to Mr. Pittman. Ms. Johansen’s and Mr. Wright’s amounts include the value of excise tax gross-up payments to be made by PacifiCorp to the Internal Revenue Service on their behalf. ScottishPower reimbursed PacifiCorp for \$1,389,937 of Mr. Pittman’s benefits.
- (f) Represents the dollar value of awards under the ScottishPower LTIP that vested and were distributed to the named officer in the form of ScottishPower American Depositary Shares.
  - (g) Represents the number of ScottishPower American Depositary Shares contingently granted in 2006, 2005 and 2004 that can be earned under the terms of the LTIP.
  - (h) Ms. Johansen resigned as a PacifiCorp executive officer effective March 21, 2006.
  - (i) Mr. Wright resigned as a PacifiCorp executive officer effective March 21, 2006.
  - (j) Mr. Pittman resigned as a PacifiCorp executive officer effective September 5, 2005.

#### Aggregated Option Exercises at March 31, 2006 and Year-End Option Values

The following table sets forth information regarding the aggregate options exercised during the past fiscal year and the option values at March 31, 2006 for each of the named executive officers. All options are for ScottishPower American Depositary Shares and include options granted under the PSIP and the ExSOP.

Name	Shares Acquired on Exercise	Value Realized	Number of Securities Underlying Unexercised Options at March 31, 2006		Value of Unexercised In-the-Money Options at March 31, 2006	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Gregory E. Abel	-	\$ -	-	-	\$ -	\$ -
Judith A. Johansen	124,125	1,561,008	-	-	-	-
Andrew P. Haller	19,046	196,042	12,288	-	161,655	-
A. Richard Walje	16,957	282,561	151,359	-	1,274,096	-
Richard D. Peach (a)	41,192	487,765	-	-	-	-
Stanley K. Watters	33,262	364,366	4,350	-	-	-
Matthew Wright (a)	-	-	40,865	-	493,979	-
Michael J. Pittman	217,813	1,933,991	25,520	-	-	-

- (a) Certain options of Mr. Peach and Mr. Wright are for ScottishPower Ordinary Shares, but are presented as American Depositary Shares.

## Long-Term Incentive Plan Awards in the Last Fiscal Year

The following table sets forth information regarding awards made in the year ended March 31, 2006 to each named executive officer under the LTIP. Each LTIP award entitles the executive officer to acquire, at no cost, the number of ScottishPower American Depositary Shares listed in the table, less any withholding for applicable taxes. An award will only vest if the ScottishPower Remuneration Committee is satisfied that certain performance measures related to the sustained underlying financial performance of the ScottishPower group and improvements in customer service standards are achieved over a period of three years commencing with the fiscal year preceding the date an award is made. The number of shares that vest depend upon ScottishPower's comparative Total Shareholder Return performance over the three-year performance period. Total Shareholder Return performance is measured against a peer group of major international energy companies. No shares vest unless ScottishPower's Total Shareholder Return performance is at least equal to the median performance of the peer group, at which point 40% of the initial award vests. If ScottishPower's performance is equal to or exceeds the top quartile, 100% of the shares vest. The number of shares that vest for performance between these two points is determined on a straight-line basis. Furthermore, the number of vested shares for each award will be prorated to reflect only the portion of the three-year performance period in which PacifiCorp was owned by ScottishPower. Participants may acquire the vested shares at any time after the third anniversary of grant.

Name	Number of Shares, Units or Other Rights	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts Under Non-Stock Price-Based Plans		
			Exercise or Threshold Shares	Target Shares (a)	Maximum Shares (b)
Gregory E. Abel			-	-	-
Judith A. Johansen	15,839	3 years	-	1,990	4,977
Andrew P. Haller	3,774	3 years	-	474	1,186
A. Richard Walje	5,374	3 years	-	676	1,689
Richard D. Peach	5,704	3 years	-	717	1,792
Stanley K. Watters	2,900	3 years	-	364	911
Matthew Wright	4,959	3 years	-	623	1,558
Michael J. Pittman	5,490	3 years	-	690	1,725

- (a) Amount to vest if threshold measures and median Total Shareholder Return performance are achieved.  
(b) Maximum number of shares exercisable reflects prorating related to acquisition by MEHC as described above.

## Employment Agreements

In September 2003, Ms. Johansen and PacifiCorp executed an employment agreement providing for a base salary of \$700,000 and a maximum annual incentive award of 75.0% of base salary. Under the agreement, she was eligible for participation in the LTIP, the ExSOP and the Retirement Plan referred to below, in addition to other benefit plans available for senior-level executives of PacifiCorp. Additionally, Ms. Johansen agreed to standard confidentiality, non-competition and non-solicitation terms. In December 2005, Ms. Johansen signed an amendment to her employment agreement with PacifiCorp and ScottishPower. The amendment:

- Provided for the termination of Ms. Johansen's employment with PacifiCorp and her resignation as an officer and director of PacifiCorp and all affiliates, including ScottishPower, effective immediately following the closing of the sale of PacifiCorp to MEHC;
- Restated her waiver of participation in the PacifiCorp Executive Severance Plan;
- Provided for the cash retention award associated with PacifiCorp's sale to MEHC previously approved by ScottishPower's Remuneration Committee, equal to one times base salary, which was contingent on the closing of PacifiCorp's sale to MEHC and also on Ms. Johansen's continued employment and her satisfactory performance of duties in the period through the sale's closing; Ms. Johansen will receive 80.0% of the retention award within 90 days of the closing of the sale and will receive the remaining 20.0% of the award 365 days from the date of the closing, provided there are no claims by MEHC against ScottishPower related to the sale;

- Modified her AIP terms to reflect a single measurement, PacifiCorp's performance against its budget, and to eliminate pro rata payout, as described above;
- Clarified the respective obligations of PacifiCorp and ScottishPower to her after the termination of her employment;
- Provided that upon termination and assuming compliance by her with the terms of her employment agreement, she would receive severance benefits equal to 12 months of salary, bonus and vehicle allowance, plus enhanced change-in-control benefits under the PacifiCorp Supplemental Executive Retirement Plan;
- Provided for a gross-up payment by PacifiCorp to Ms. Johansen to cover any excise tax payable in connection with separation payments, as well as certain health insurance and other benefits following her employment termination; and
- Added certain customary obligations relating to non-disparagement and conflicts of interest.

In December 2004, Mr. Pittman and PacifiCorp executed an employment agreement providing for a base salary of \$325,000 and a maximum annual incentive award of 100.0% of base salary (unless otherwise modified by the Remuneration Committee). Under the agreement, he was eligible for participation in the LTIP, the ExSOP and the Retirement Plan, in addition to other benefit plans available for senior level executives of PacifiCorp. Additionally, Mr. Pittman agreed to standard confidentiality, non-competition and non-solicitation terms.

In October 2005, PacifiCorp entered into a compromise agreement with PHI and Mr. Pittman that superseded Mr. Pittman's employment agreement with PacifiCorp and ScottishPower and documented the terms of his separation from the companies following a ScottishPower corporate restructuring that eliminated his position. Under his employment agreement, Mr. Pittman was entitled to severance benefits equal to 12 months of salary, bonus and vehicle allowance and 6 months of continued health insurance coverage. The Compromise Agreement supplemented those benefits with enhancements generally comparable to those payable under the PacifiCorp Executive Severance Plan for a termination following a change in control of PacifiCorp, including an additional 12 months of salary, bonus and vehicle allowance and health insurance coverage for an additional 18 months. ScottishPower reimbursed PacifiCorp for the cost of the supplemental benefits provided by the compromise agreement.

Mr. Abel's employment agreement with MEHC is described in MEHC's Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 001-14881).

### **Retention Agreements**

In May 2005, PacifiCorp and its Senior Vice President and Chief Financial Officer, Richard D. Peach entered into a retention agreement entitling Mr. Peach to an \$80,000 retention bonus on June 1, 2006 if he remains employed at an acceptable level of performance in PacifiCorp's corporate finance department through May 30, 2006 and has developed a succession and risk mitigation plan for his department. If Mr. Peach's employment is terminated involuntarily due to a workforce reduction during the term of the retention agreement, he will receive the full amount of any unpaid retention bonuses.

In August 2005, PacifiCorp's named executive officers (other than Mr. Abel, Ms. Johansen and Mr. Pittman) entered into agreements with ScottishPower for awards under the Transaction Incentive Program, which is a \$6.0 million pool created by ScottishPower for retention incentives during the period of completion of ScottishPower's sale of PacifiCorp to MEHC. The agreement signed by each named executive officer provided for a transaction incentive award in an amount equal to the executive officer's base salary (in Mr. Peach's case, this amount was adjusted for his existing retention agreement), payable as follows:

- 25.0% of the award was paid within one month of execution and delivery of the award agreement;
- 50.0% of the award is payable three months after the closing of PacifiCorp's sale to MEHC, provided there are no claims by MEHC against ScottishPower; and

- 25.0% of the award is payable 12 months after the closing, again as long as there are no claims by MEHC against ScottishPower.

Continued employment by PacifiCorp, observance of confidentiality obligations and satisfactory performance in support of the transaction until the sale's completion are conditions to the executive officer's receipt of these payments. Award payments are the obligation of ScottishPower. Ultimate determinations of award eligibility will be made by ScottishPower's Chief Executive Officer, subject to review by its Remuneration Committee.

On May 24, 2006, PacifiCorp entered into certain retention agreements with each of Messrs. Haller and Peach. Under each retention agreement, provided that the executive has not voluntarily resigned or had his employment with PacifiCorp terminated for cause prior to December 31, 2006 for Mr. Haller and November 22, 2006 for Mr. Peach, the executive (i) will be entitled to the same benefits the executive would have been entitled to under PacifiCorp's Supplemental Executive Retirement Plan ("SERP") had the executive terminated his employment during the two-month window period following the first anniversary of a change in control, and (ii) will be entitled, upon any termination on or following the applicable retention date, to the same benefits the executive would have been entitled to under PacifiCorp's Executive Severance Plan had such termination occurred in connection with a material alteration in position or compensation within the 24-month period following a change in control.

#### **Severance Arrangements**

PacifiCorp's Executive Severance Plan provides severance benefits to certain executive-level employees who in the past were designated by the PacifiCorp Compensation Committee, but who in the future will be designated by the Chairman of the Board of Directors. The executive officers named in the Summary Compensation Table (other than Mr. Abel and Ms. Johansen) participate in this plan.

Severance benefits are payable by PacifiCorp for voluntary terminations as a result of a certain material alterations in position or compensation that have a detrimental impact on the executive's employment or involuntary terminations (including a PacifiCorp-initiated resignation) for reasons other than cause. Severance payments generally equal one or two times the executive's annual cash compensation, three months of health insurance benefits and outplacement services.

The Executive Severance Plan also provides enhanced severance benefits in the event of certain terminations during the 24-month period following a qualifying change-in-control transaction; with respect to MEHC's acquisition of PacifiCorp, this qualifying period commenced on May 23, 2005. Executives designated by the PacifiCorp Compensation Committee or Chairman, as applicable, are eligible for change-in-control benefits resulting from either a PacifiCorp-initiated termination without cause or a resignation generally within two months after certain material alterations in position or compensation. If qualified for the enhanced severance benefits, an executive would receive severance pay in an amount equal to either two, two and one-half or three times the annual cash compensation of the executive, depending on the level set by the PacifiCorp Compensation Committee or Chairman, as applicable. PacifiCorp is required to make an additional payment to compensate the executive for the effect of any excise tax. The executive would also receive continuation of subsidized health insurance from six to 24 months, depending on length of service, and outplacement services.

#### **Retirement Plans**

PacifiCorp has adopted non-contributory defined benefit retirement plans for its employees, other than employees subject to collective bargaining agreements that do not provide for coverage. Certain executive officers, including the executive officers named in the Summary Compensation Table other than Mr. Abel, are also eligible to participate in PacifiCorp's non-qualified SERP. The following description assumes participation in both the Retirement Plan and the SERP. Participants receive benefits at retirement payable for life based on length of service with PacifiCorp and average pay in the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose would include salary and AIP payments reflected in the Summary Compensation Table above. Benefits are based on 50.0% of final average pay plus 1.0% of final average pay for each year that PacifiCorp meets certain performance goals set for each fiscal year by, in the past, the PacifiCorp Compensation Committee, and now

the Chairman of the Board of Directors. The maximum benefit is 65.0% of final average pay. Participants may also elect actuarially equivalent alternative forms of benefits. Retirement benefits are adjusted to reflect social security benefits as well as certain prior employer retirement benefits. Participants are entitled to receive full benefits upon retirement after age 60 with at least 15 years of service. Participants are also entitled to receive reduced benefits upon early retirement after age 55 or after age 50 with at least 15 years of service and five years of participation in the SERP.

The following table shows the estimated annual retirement benefit payable upon retirement at age 60 as of March 31, 2006. Amounts in the table reflect payments from the Retirement Plan and the SERP combined, prior to any offset of projected social security benefits and benefits paid from any prior employer plan.

**Estimated Annual Pension at Retirement (a)**

Final Average Pay at Retirement Date		Years of Service (b)			
		5	15	25	30
\$	200,000	\$ 43,333	\$ 130,000	\$ 130,000	\$ 130,000
	400,000	86,667	260,000	260,000	260,000
	600,000	130,000	390,000	390,000	390,000
	800,000	173,333	520,000	520,000	520,000
	1,000,000	216,667	650,000	650,000	650,000

- (a) The benefits shown in this table assume that the individual will remain in the employ of PacifiCorp until retirement at age 60, that the Retirement Plan and the SERP will continue in their present form and that PacifiCorp achieves its performance goals under the SERP in all years.
- (b) The number of credited years of service used to compute aggregate benefits under the Retirement Plan and the SERP are five for Ms. Johansen, five for Mr. Haller, 20 for Mr. Walje, 11 for Mr. Peach, 24 for Mr. Watters, 19 for Mr. Wright and 26 for Mr. Pittman.

**ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS**

All outstanding shares of common stock of PacifiCorp are indirectly owned by MEHC, 666 Grand Avenue, Des Moines, Iowa 50309. MEHC is a consolidated subsidiary of Berkshire Hathaway, which owns approximately 88.2% of MEHC's common stock (86.6% on a diluted basis). The balance of MEHC's common stock is owned by a private investor group comprised of Walter Scott, Jr. (including family members and related entities), David L. Sokol and Gregory E. Abel, PacifiCorp's Chairman and Chief Executive Officer.

Based on a Schedule 13G filed with the SEC on February 15, 2006, CAM North America, LLC, 399 Park Avenue, New York, NY 10022, is the beneficial owner of 38,910 shares, or 5.19%, of PacifiCorp's outstanding 7.48% Series Preferred Stock.

No PacifiCorp executive officers or directors own shares of PacifiCorp's preferred stock or shares of the Class B common stock of Berkshire Hathaway. The following table sets forth certain information as of March 31, 2006 regarding the beneficial ownership of common stock of MEHC and the Class A common stock of Berkshire Hathaway by (i) each of the executive officers named in the Summary Compensation Table under Item 11. Executive Compensation above, (ii) each director of PacifiCorp as detailed under "Item 10. Directors and Executive Officers of the Registrant," and (iii) all executive officers and directors of PacifiCorp as a group.

Beneficial Owner	MidAmerican Common Stock		Berkshire Hathaway Class A Common Stock	
	Number of shares Beneficially Owned (a)	Percentage of Class (a)	Number of shares Beneficially Owned (a)	Percentage of Class (a)(c)
Gregory E. Abel (b)	749,992	1.01 %	-	- %
Douglas L. Anderson	-	-	3	*
William J. Fehrman	-	-	-	-
Brent E. Gale	-	-	-	-
Patrick J. Goodman	-	-	2	*
Andrew P. Haller	-	-	-	-
Nolan E. Karras	-	-	-	-
A. Robert Lasich	-	-	-	-
Mark C. Moench	-	-	1	*
Richard D. Peach	-	-	-	-
A. Richard Walje	-	-	-	-
Stanley K. Watters	-	-	-	-
Bruce N. Williams	-	-	-	-
All executive officers and directors as a group (13 persons)	749,992	1.01 %	6	*

- (a) Includes shares as to which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.
- (b) Includes options to purchase 649,052 shares of common stock which are exercisable within 60 days. Excludes 10,041 shares reserved for issuance pursuant to a deferred compensation plan.
- (c) \* Indicates beneficial ownership of less than one percent of all outstanding shares.

### ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

#### RELATED TRANSACTIONS

According to the terms of Andrew P. Haller's offer letter, PacifiCorp made a \$200,000.00 loan to Mr. Haller on May 21, 2001 for the repayment of obligations to his former employer. The loan accrues interest at the annual rate of 4.74%. Mr. Haller has repaid \$146,793.50 of the loan amount. The largest outstanding loan balance, including accrued interest, at any time during the year ended March 31, 2006 was \$86,206.50 at July 11, 2005. As of March 31, 2006, the outstanding loan balance was \$55,016.83, including accrued interest. The remaining balance and interest is payable in one payment of \$32,988.56 on June 30, 2006 and one payment of \$23,730.98 on June 30, 2007.

See "Item 8. Financial Statements and Supplementary Data – Note 4 – Related-Party Transactions" for other information on related-party transactions.

### ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The ScottishPower Audit Committee retained PricewaterhouseCoopers LLP, independent certified public accountants, as PacifiCorp's independent registered public accounting firm for the year ended March 31, 2006, which was affirmed by the MEHC Audit Committee.

#### Fees and Pre-Approval Policy

MEHC's Audit Committee has an Audit and Non-Audit Services Pre-Approval Policy (the "Policy") which sets forth the procedures and the conditions pursuant to which services to be performed by the independent registered public accountant are to be pre-approved. Pursuant to the Policy, certain services described in detail in the Policy may be pre-approved on an annual basis together with pre-approved maximum fee levels for such services. The services eligible for annual pre-approval consist of services that would be included under the categories of Audit

fees, Audit-related fees and Tax fees below. If not pre-approved on an annual basis, proposed services must otherwise be separately approved prior to being performed by the independent registered public accountant. In addition, any services that receive annual pre-approval but exceed the pre-approved maximum fee level also will require separate approval by the Audit Committee prior to being performed. The PacifiCorp Board of Directors has not adopted any pre-approval policy that is in addition to or different than the MEHC Audit Committee's pre-approval policy.

ScottishPower's Audit Committee used a pre-approval policy for PricewaterhouseCoopers' services and fees. This policy detailed the services that could be provided by the independent registered public accounting firm, and required that where the initial fee value for any services permitted in accordance with the policy exceeded £100,000 (or its United States dollar equivalent), the assignment had to be reviewed and authorized by the Chairman of the ScottishPower Audit Committee with the concurrence of the ScottishPower Finance Director. Any services authorized by the Chairman were reported to the ScottishPower Audit Committee at its next scheduled meeting, and fees paid to the independent registered public accounting firm were reported regularly to the ScottishPower Audit Committee.

The following table presents fees billed by PricewaterhouseCoopers for the years ended March 31, 2006 and 2005.

(Millions of dollars)	Year Ended March 31,					
	2006		2005			
Audit fees	\$	1.4	42.4 %	\$	1.4	30.4 %
Audit-related fees		0.4	12.2		1.1	23.9
Tax fees		1.4	42.4		2.0	43.5
Other fees		0.1	3.0		0.1	2.2
Total	\$	3.3	100.0 %	\$	4.6	100.0 %

**Audit fees** are for the audit and review of PacifiCorp's financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States), including comfort letters, statutory and regulatory audits, consents and services related to SEC matters.

**Audit-related fees** are for assurance and related services that are related to the audit or review of PacifiCorp's financial statements, including employee benefit plan audits, due diligence services and financial accounting and reporting consultation.

**Tax fees** are fees for tax compliance services and related costs.

**Other fees** are mainly for services rendered in connection with requests from state regulatory commissions and for regulatory matters.

## PART IV

### ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

- (a) 1. The list of all financial statements filed as a part of this report is included in Item 8. Financial Statements and Supplementary Data.
2. Schedules:\*
- \* All schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements included under "Item 8. Financial Statements and Supplementary Data."
3. Exhibits:

<u>Exhibit Number</u>	<u>Exhibit Title</u>
2.1(a)*	Agreement and Plan of Merger, dated as of December 6, 1998, by and among Scottish Power plc, NA General Partnership, Scottish Power NA 1 Limited and Scottish Power NA 2 Limited. (Exhibit 1 to the Form 6-K, dated December 11, 1998, filed by Scottish Power plc, File No. 1-14676).
2.1(b)*	Amended and Restated Agreement and Plan of Merger, dated as of December 6, 1998, as amended as of January 29, 1999 and February 9, 1999, and amended and restated as of February 23, 1999, by and among New Scottish Power PLC, Scottish Power plc, NA General Partnership and PacifiCorp (Exhibit (2)b, Form 10-K for year ended December 31, 1998, File No. 1-5152).
3.1*	Third Restated Articles of Incorporation of PacifiCorp (Exhibit (3)b, Form 10-K for the year ended December 31, 1996, File No. 1-5152).
3.2	Bylaws of PacifiCorp, as amended May 23, 2005.
4.1*	Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and JP Morgan Chase Bank (formerly known as The Chase Manhattan Bank), Trustee, Ex. 4-E, Form 8-B, File No. 1-5152, as supplemented and modified by 18 Supplemental Indentures as follows:

<u>Exhibit Number</u>	<u>File Type</u>	<u>File Date</u>	<u>File Number</u>
(4)(b)			33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-Q	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Year ended December 31, 1994	1-5152
(4)b	10-K	Year ended December 31, 1995	1-5152
(4)b	10-K	Year ended December 31, 1996	1-5152
4(b)	10-K	Year ended December 31, 1998	1-5152
99(a)	8-K	November 21, 2001	1-5152
4.1	10-Q	Quarter ended June 30, 2003	1-5152
99	8-K	September 8, 2003	1-5152
4	8-K	August 24, 2004	1-5152
4	8-K	June 13, 2005	1-5152

4.2\* Third Restated Articles of Incorporation and Bylaws. See 3.1 and 3.2 above.

In reliance upon item 601(4)(iii) of Regulation S-K, various instruments defining the rights of holders of long-term debt of the Registrant and its subsidiaries are not being filed because the total amount authorized under each such instrument does not exceed 10.0% of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

- 10.1\* Judith Johansen Employment Agreement (Exhibit 10.3, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.2\* Amendment No. 1 to Employment Agreement among PacifiCorp, Scottish Power plc and Judith Johansen, dated as of December 20, 2005 (Exhibit 10, Current Report on Form 8-K, filed December 23, 2005, File No. 1-5152).
- 10.3\* Compensation Reduction Plan (Exhibit 10.5, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.4\* Amendment No. 1 to PacifiCorp Compensation Reduction Plan, dated effective July 1, 2003 (Exhibit 10.2, Quarterly Report on Form 10-Q, filed November 10, 2005, File No. 1-5152).
- 10.5\* Amendment No. 2 to PacifiCorp Compensation Reduction Plan, dated effective September 20, 2005 (Exhibit 10.3, Quarterly Report on Form 10-Q, filed November 10, 2005, File No. 1-5152).
- 10.6\* Executive Severance Plan (Exhibit 10.3, Current Report on Form 8-K, filed May 6, 2005, File No. 1-5152).
- 10.7\* Amendment to PacifiCorp Executive Severance Plan, dated effective October 31, 2005. (Exhibit 10.2, Quarterly Report on Form 10-Q, filed February 14, 2006, File No. 1-5152).
- 10.8\* Supplemental Executive Retirement Plan (Exhibit 10.7, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.9\* Richard Peach Retention Agreement (Exhibit 10.4, Current Report on Form 8-K, filed May 6, 2005, File No. 1-5152).
- 10.10\* Andrew Haller Promissory Note (Exhibit 10.11, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.11\* Form of Transaction Incentive Program Award Agreement for Named Executive Officers (Exhibit 10, Current Report on Form 8-K, filed September 1, 2005, File No. 1-5152).
- 10.12\* Michael Pittman Employment Agreement (Exhibit 10.4, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.13\* Compromise Agreement among PacifiCorp, PacifiCorp Holdings, Inc. and Michael J. Pittman, dated October 4, 2005 (Exhibit 10.4, Quarterly Report on Form 10-Q, filed November 10, 2005, File No. 1-5152).
- 10.14 Andrew Haller Retention Agreement.
- 10.15 Richard Peach Retention Agreement.
- 12.1 Statements of Computation of Ratio of Earnings to Fixed Charges.

- 12.2        Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
- 23         Consent of PricewaterhouseCoopers LLP.
- 24         Power of Attorney.
- 31.1       Section 302 Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a).
- 31.2       Section 302 Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a).
- 32.1       Section 906 Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350.
- 32.2       Section 906 Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350.
- 99.1\*      Stock Purchase Agreement among Scottish Power plc, PacifiCorp Holdings, Inc. and MidAmerican Energy Holdings Company (Exhibit 99.1, Current Report on Form 8-K, filed May 24, 2005, by MidAmerican Energy Holdings Company, File No. 001-14881).
- 99.2\*      Amendment No. 1 to Stock Purchase Agreement, dated as of March 21, 2006, by and among Scottish Power plc, PacifiCorp Holdings, Inc. and PPW Holdings LLC (as successor-in-interest to MidAmerican Energy Holdings Company) (Exhibit 10.1, Current Report on Form 8-K, filed March 21, 2006, by MidAmerican Energy Holdings Company, File No. 001-14881).

\*Incorporated herein by reference.

- (b)    See (a) 3. above.
- (c)    See (a) 2. above.



[illegible]

) Director

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